SECTION ONE

INTRODUCTION

The U.S. Environmental Protection Agency (EPA) is regulating the discharge of synthetic-based drilling fluids (SBFs), other non-aqueous drilling fluids, and the resultant contaminated drill cuttings from drilling operations. This Economic Analysis (EA) report is written to address the economic impacts of this Final Effluent Limitation Guidelines for Synthetic-Based and Other Non-Aqueous Drilling Fluids. Currently, effluent guidelines pertaining to the discharge of drilling fluids address two specific types of fluids:

- Oil-based drilling fluids (OBFs) that use diesel and mineral oil, which are prohibited from being discharged.
- Water-based drilling fluids (WBFs), which can be discharged in certain limited offshore regions subject to meeting certain discharge requirements, including a sheen test and an aqueous toxicity test.

In many cases, SBFs and SBF-contaminated cuttings are not clearly prohibited from discharge, nor are they clearly allowed to be discharged, since the relevant effluent guidelines that define allowable conditions for discharge of drilling fluids and cuttings were developed before SBFs and other non-aqueous drilling fluids were widely available. To address this lack of clarity in existing effluent guidelines and to more clearly define allowable discharge conditions for SBF and other non-aqueous drilling wastes, EPA is promulgating Final Effluent Limitations Guidelines for Synthetic-Based and Other Non-Aqueous Drilling Fluids (known hereafter as the SBF Guidelines; where this report uses the term SBF, other non-aqueous fluids and associated cuttings are included in this term). The analyses in this report rely on publicly available or industry-provided data exclusively.

The SBF Guidelines will control the discharge of SBF-contaminated drill cuttings (SBF-cuttings). Discharge of the fluids themselves will be prohibited. Furthermore, the SBF guidelines will only apply where discharge of drilling waste is currently allowed. Because drilling fluids and cutting may only be discharged in a portion of offshore areas, the operations that might be affected by this proposed rulemaking will be limited to a subset of the U.S. oil and gas industry. EPA subdivides the oil and gas extraction point source category into several major subcategories, including the Onshore Subcategory, the Stripper Subcategory (marginal producing wells), the Beneficial Use Subcategory (wells whose produced water can be used beneficially for irrigation or other purposes), the Coastal Subcategory (wells located in water located landward of the territorial seas and associated wetlands), and the Offshore Subcategory (see 40 CFR Part 435 for more details on the subcategorization of the oil and gas extraction point source category). Discharge of drilling fluids or drill cuttings into surface waters is completely prohibited for the Onshore subcategory, no matter what the composition of the fluid, as is the discharge of any drilling fluid in regions defined as coastal, with the exception of Cook Inlet, Alaska. Furthermore, discharge of any type of drilling fluid also is prohibited within 3 miles of shore in the Offshore region except Offshore Alaska, where there is no distance restriction.[1]

Currently, the potentially affected offshore regions where drilling activity is taking place include the Gulf of Mexico, California, and Alaska. Drilling activity is also underway in the coastal region of Cook Inlet, Alaska.[2] The EA for EPA's proposal of this rulemaking[3] discussed the Alaska and California drilling activities in detail; no further information on these areas appears in this report.

[1]Stripper wells are defined by level of production and Beneficial Use by produced water disposition. These wells follow the requirements set by their location. That is, discharge of drilling fluids or drill cuttings is prohibited for Stripper and Beneficial Use wells when they are located within onshore, coastal, and offshore regions where discharge is prohibited.

[2]See discussions in the *Economic Impact Analysis of Final Effluent Limitations Guidelines and Standards of Performance for the Offshore Oil and Gas Industry*, U.S. EPA, EPA-821-R-93-001, January 1993, (hereafter called "Offshore EIA") and the *Economic Impact Analysis of Final Effluent Limitations Guidelines and Standards for the Coastal Subcategory of the Oil and Gas Extraction Point Source Category*, U.S. EPA, EPA 821-R-96-022, October 1996 (hereafter called "Coastal EIA"). Outside of these regions, significant amounts of drilling activity are unlikely in the near future but it is reasonable to expect that the economic characteristics of projects elsewhere would lie within the range of projects in areas already considered.

[3]See Section Three of the *Economic Analysis of Proposed Effluent Limitations Guidelines and Standards for Synthetic-Based Drilling Fluids and Other Non-Aqueous Drilling Fluids in the Oil and Gas Extraction Point Source Category,* U. S. EPA, EPA 821-B-98-020, February 1999.

This report contains only an updated analysis of impacts on drilling activities in these regions. The EA industry profile and most of the analyses focuses on the Federal Outer Continental Shelf (OCS) region of the Gulf of Mexico and the state waters off Texas between 3 miles and 3 leagues. (Texas defines state waters out to 3 leagues, unlike most other states). Furthermore, within this area, the profile and many of the analyses focus primarily on deepwater Gulf of Mexico activities, since it is these drilling operations that are likeliest to experience impacts from the Final SBF Guidelines. The profile of shallow water Gulf of Mexico drilling operations is, however, updated to include more recent financial information and to add operators who have only recently (1998 and 1999) begun to drill in the Gulf of Mexico Offshore region.

This report is divided into eight sections. Following this introduction, Section Two presents sources of data that have been added since proposal, Section Three presents the updated industry profile, and Section Four discusses the regulatory costs of options under consideration for the rulemaking. Section Five discusses the impacts of the final rule on firms, well drilling, and production, and also briefly discusses secondary impacts such as those on employment, output, inflation, balance of trade and other industries. This section adds a discussion of a computer model that simulates the financial conditions at deepwater Gulf oil and gas drilling and production projects to address industry concerns that the deepwater Gulf has unique economic and financial conditions and thus analyses performed for the Offshore Guidelines are not sufficient for analyzing impacts of zero discharge on these projects. Section Six presents EPA's initial regulatory flexibility analysis as required under the Regulatory Flexibility Act (RFA) as amended by the Small Business Regulatory Enforcement Fairness Act (SBREFA). Section Seven provides a brief summary of costs and benefits of the rule. Finally, Section Eight presents EPA's methodology and results for analyzing the environmental justice implications of a zero discharge option.

The EA also contains several appendices. Appendix A documents how the per-well incremental costs were derived from EPA's engineering cost estimates. Appendix B presents an overview of EPA's deepwater Gulf financial model and a detailed line-by-line explanation of the model assumptions and calculations. Appendix C presents the details of the Environmental Justice analysis summarized in Section Eight.

SECTION TWO

SOURCES OF DATA

As discussed in Section One, for this analysis, EPA is relying on public data and data that industry has submitted on a voluntary basis. This section discusses the primary sources of updated data used throughout this document that have been added since the SBF Guidelines were proposed.

Primarily, EPA has added data necessary for modeling financial impacts on oil and gas projects in the deepwater Gulf of Mexico. Much of this data was downloaded from Minerals Management Services (MMS) website and included information on lease ownership and costs, 1998 production, 1998 and 1999 drilling data, reserve history data, platform information, and pipeline information**.** Additionally, industry sources provided updated data on various operating costs, platform construction costs, deepwater well drilling costs, etc. MMS also provided information on existing and planned oil and gas projects in the deepwater regions. For more information on these data sources and an overview of the data provided by these sources, see *Summary of Data To Be Used in Economic Modeling*, March 2000, which is located in Section III.G of the Rulemaking Record.

Other updated sources of data used in the economic analyses include:

- *Development Document for Final Effluent Guidelines and Standard for Synthetic-Based Drilling Fluids and Other Non-Aqueous Drilling Fluid in the Oil and Gas Extraction Point Source Category*, U.S. EPA, 2000 (EPA 821-B-00-013, hereafter known as the SBF Development Document). This document supports this rulemaking and presents all cost data.

- *Oil and Gas Journal,* Special Report: Operating, financial results for OGJ 200. Volume 98(42). October 16, 2000.

Additional sources, including those used at proposal, are cited where they are mentioned in this report.

SECTION THREE

PROFILE OF AFFECTED OFFSHORE DRILLING OPERATIONS

3.1 INTRODUCTION

This profile focuses on the drilling activity taking place in the Gulf of Mexico (GOM or "the Gulf") where discharge of drilling fluids with controls is authorized. For overview information on GOM, California, and Alaska drilling operations, see the EA for the proposal.

This section begins with an updated discussion of the firms that are drilling both in deepwater and shallow water regions of the Gulf and presents financial information on these firms. It then continues with a focus on deepwater drilling operations in the Gulf. The number of wells drilled—a pertinent factor for calculating the cost of the regulation—has not been changed from proposal.

3.2 UPDATED PROFILE OF THE GULF OF MEXICO

3.2.1 Current Practices

The Gulf of Mexico beyond three miles from shore is the most active oil and gas region of interest.[1] Nearly all exploration and development activities in the Gulf are taking place in the Western Gulf of Mexico, that is, the regions off the Texas and Louisiana shores. Very little drilling is occurring off Mississippi, Alabama, and Florida at this time although oil and gas deposits are known to exist. The Western Gulf also is associated with the only known current use of SBF and discharge of SBF-cuttings. SBFs are used preferentially in drilling deeper formations, in deeper water, in formations of reactive shale, and during directional drilling. They generally replace traditional OBFs for these purposes.

[1]Under the Clean Water Act, state authority extends only three miles from shore. MMS has leasing authority beyond three leagues (approximately 10 miles from shore) for Florida and Texas. The Railroad Commission of Texas (RRC) provided annual counts of wells drilled in state waters in the three miles to three leagues area for 1996 - 1998, but could not provide the operator names for these wells.

3.2.2 Platforms

The number of platforms has not been updated since the proposal. In 1998, EPA updated its count of active platforms in the federal OCS region of the Gulf of Mexico that was originally presented in the Offshore EIA,[2] using the Minerals Management Service (MMS) Platform Inspection System, Complex/Structure database as of May 1998. The database was downloaded and counts of structures were noted. Abandoned structures, platforms considered production facilities only, platforms with no productive wells, platforms with missing production data, and platforms with service wells only were counted and removed from totals, in the same way as was done for the Offshore Effluent Guidelines. Out of a total of 5,026 structures, EPA identified 2,381 platforms that fit this description (see Table 3-1).

Table 3-1

Identification of Structures in the Gulf of Mexico OCS

Category	Count	Remaining Count
All Structures	5,026	5,026
Abandoned Structures	1,403	3,623
Structures classified as production structures, i.e., with no well slots and production equipment	245	3,378
Structures known not to be in production	688	2,690
Structures with missing information on product type (oil or gas or both)	309	2,381
Structures whose drilled well slots are used solely for injection, disposal, or as a water source	0	2,381

Source: Minerals Management Service, Platform Inspection System, Complex/Structure.

[2] *Economic Impact Analysis of Final Effluent Limitations Guidelines and Standards of Performance for the Offshore Oil and Gas Industry*, U.S. EPA, EPA-821-R-93-001, January 1993.

3.2.3 Operators

The expenditures required to comply with the SBF Guidelines will be financed by the affected firms and their investors. Affected firms can be divided into two basic categories. The first category consists of the major integrated oil companies, which are characterized by a high degree of vertical integration (i.e., their activities encompass both "upstream" activities—oil exploration, development, and production—and "downstream" activities—transportation, refining, and marketing). The second category of affected firms consists of independents engaged primarily in exploration, development, and production of oil and gas. Independents typically are not involved in downstream activities. Some independents are strictly producers of oil and gas, while others maintain some service operations, such as contract drilling and well servicing. The major integrated oil companies are generally larger than the independents. As a group, the majors typically produce more oil and gas, earn significantly more revenue and income, and have considerably more assets and greater financial resources than most independents. Furthermore, majors tend to be relatively homogeneous in terms of size and corporate structure. All majors are considered large firms under the Regulatory Flexibility Act (RFA) guidelines and generally are C corporations (i.e., the corporation pays income taxes).

Independents can vary greatly by size and corporate structure. Larger independents tend to be C corporations; small firms might also pay corporate taxes, but they also can be organized as S corporations (which elect to be taxed at the shareholder level rather than the corporate level under subchapter S of the Internal Revenue Code). Small firms also might be organized as limited partnerships, sole proprietorships, etc., whose owners—not the firms—pay taxes.

For this profile, EPA is relying on information developed by MMS that includes wells drilled in federal waters from 1995 through 1999 together with the identification number of the operator. These data are summarized from MMS's Technical Information Management System (TIMS) and from the publicly available data file on boreholes available from the MMS website. Using TIMS data, MMS grouped wells by location (Gulf drilling operations were tallied separately), water depth (up to 999 ft and 1,000 ft or more), and by type (exploratory or development). MMS also provided a list of operators by operator number. EPA linked the name of the operators to wells drilled using the operator number. EPA then updated this listing of operators using 1999 borehole data from the MMS website (MMS, 1999). Names of all operators who had drilled any well in any of the five years were then compiled. The first column of Table 3-2 shows these operators. EPA then used the Security and Exchange Commission's (SEC's) EDGAR database, which provides access to various filings by publicly held firms, such as 8Ks and 10Ks. The former documents are useful for determining mergers and acquisitions in more detail, and 10Ks provide annual balance sheet and income statements, as well as listing corporate subsidiaries. The information in the EDGAR database as well as data from the OGJ 200, Lycos Companies Online (Lycos, 2000), and Hoovers Online (Hoovers, 2000) were used to identify parent companies or recent changes of ownership (for example, The Coastal Corporation and El Paso Energy Corporation announced a merger in January 2000). Note that EPA's analysis is based on the status of the industry as of October 2000. Merger and acquisitions continue to occur among this group of firms.

Table 3-2 shows the results of EPA's search for parent companies and recent acquisitions. EPA followed the Small Business Administration's (SBA's) definition of affiliation in determining the point in the corporate hierarchy at which to classify a firm as large or small. Small firms that are affiliated (e.g., 51 percent owned) by firms defined as large by SBA's standards (13CFR Part 121) are not considered small for the purposes of regulatory flexibility analysis (see Section Six for more details).

Once EPA accounted for these relationships and transactions, EPA's count of potentially affected firms in the Gulf of Mexico became 100 firms, of which 15 are listed as majors.[3] Thirteen firms are identified as foreign owned (not including majors such as Shell Oil, which is affiliated with Royal Dutch/Shell Group), and these firms are included in the analysis. Nonforeign independents total 72 firms, including those not listed in PennWell as majors or independents.[4]

As mentioned in footnote 1, Texas could not provide EPA with the names of the firms drilling in the area between three miles and three leagues. However, it is likely that the same set—or nearly the same set—of firms that are drilling in federal waters are also drilling in this area off Texas.

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[3] *USA Oil Industry Directory*. PennWell Directories; division of PennWell Publishing Co. Tulsa, Oklahoma, 37th edition. 1998.

[4] *Ibid.*

Table 3-2

Companies Drilling in the Federal Offshore Gulf of Mexico
Name Changes or Ownership Defined

Company as listed in MMS, 1997 and 1999	Company listed by Corporate Parent
AEDC (USA) Inc.	AEDC (USA) Inc.
Agip Petroleum Company, Inc.	Agip Petroleum Company, Inc.
Amerada Hess Corporation	Amerada Hess Corporation
American Exploration Company	S.A.Loius Dreyfus et Cie (France)
American Explorer	Petroquest Energy, Inc.
Amoco Petroleum Company	BP Amoco Corporation (U.S.)
Anadarko Petroleum Corporation	Anadarko Petroleum Corporation
Apache Corporation	Apache Corporation
Apex Oil and Gas, Inc.	Apex Oil and Gas, Inc.
Ashland Exploration Holdings, Inc.	Statoil (Norway)
ATP Oil and Gas Corporation	ATP Oil and Gas Corporation
Aviara Energy Corporation	HW&T Acquisition Company
Aviva Petroleum	Aviva Petroleum
Barrett Resources Corporation	Barrett Resources Corporation
Basin Exploration, Inc.	Basin Exploration, Inc.
Bellwether Exploration Company	Bellwether Exploration Company
BHP Petroleum (Americas), Inc.	BHP Petroleum (Americas), Inc.
Bois d'Arc Operating Corporation	Bois d'Arc Operating Corporation
Bois d’Arc Offshore Limited	Bois d'Arc Operating Corporation
BP Exploration & Oil, Inc.	BP Amoco Corporation (U.S.)
British Borneo Exploration, Inc.	British Borneo Exploration, Inc.
BT Operating Company	BT Energy
Burlington Resources Offshore, Inc.	Burlington Resources, Inc.
Cairn Energy USA, Inc.	Meridian Resource Corporation
Cal Resources, LLC	Shell Oil Company
Callon Petroleum Operating Company	Callon Petroleum Limited
Calpine Natural Gas	Calpine Corporation
Century Exploration Company	Century Exploration Company
Century Offshore Management Corporation	Century Offshore Management Corporation
Challenger Minerals, Inc.	Global Marine
Chateau Oil and Gas, Inc.	Chateau Oil and Gas, Inc.
Chevron USA, Inc.	Chevron Corporation
Chieftain International (U.S.), Inc.	Chieftain International, Inc.
Coastal Oil and Gas Corporation*	El Paso Energy Corporation
Cockrell Oil Corporation	Cockrell Oil Corporation
Conoco, Inc.	Conoco, Inc.
Consolidated Natural Gas Company*	Dominion Resources, Inc.
CXY Energy Offshore, Inc.	Canadian Occidental Petroleum, Ltd.
Davis Petroleum Corporation	Davis Petroleum Corporation
Domain Energy Corporation	Range Resources Corporation

Table 3-2 (cont.)

Company as listed in MMS, 1997 and 1999	Company listed by Corporate Parent
Dominion Exploration and Production	Dominion Resources, Inc.
EEX Corporation	EEX Corporation
El Paso Production	El Paso Energy Corporation
Elf Aquitaine	Total Fina Elf S.A.
Energy Development Corporation	Noble Affiliates
Energy Partners	Energy Partners Limited
Energy Resource Technology, Inc.	Cal Dive International Inc.
Enron Oil and Gas Company	EOG Resources, Inc
Enserch Exploration, Inc.	EEX Corporation
Equitable Resources Energy Company	Equitable Resources, Inc.
Exxon-Mobil Corporation	Exxon-Mobil Corporation
Fairways Specialty Sales & Service	Fairways Specialty Sales & Service
Falcon Offshore Operating Company	R&B Falcon
Fina Oil and Chemical Company	Total Fina Elf S.A.
Flextrend Development Company, LLC	El Paso Energy Corporation
Forcenergy, Inc.	Forcenergy, Inc.
Forest Oil Corporation	Forest Oil Corporation
Freeport-McMoran Resources Partners, LLC	McMoran Exploration Company
F-W Oil Interests, Inc.	Prime Natural Resources
Global Production	Global Industries
Gulfstar Energy, Inc.	Domain Energy Corporation
Hall-Houston Oil Company	Hall-Houston Oil Company
Houston Exploration Company	Houston Exploration Company
Howell Petroleum	Howell Corporation
Hunt Oil Company	Hunt Consolidated Inc.
HW&T Acquisition Company	Hunt Oil Company
IP Petroleum Company, Inc.	International Paper
JM Huber Corporation	JM Huber Corporation
Juniper Energy	Enron Corporation
Kelly Oil Company	Contour Energy Company
Kerr McGee Corporation	Kerr McGee Corporation
Kerr McGee Oil and Gas Corporation	Kerr McGee Corporation
King Ranch Energy, Inc.	St. Mary Land and Exploration Company
Linder Oil Company, A Partnership	Linder Oil Company, A Partnership
LLOG Exploration Offshore, Inc.	LLOG Exploration Offshore, Inc.
Louis Dreyfus Natural Gas Corporation	S.A.Loius Dreyfus et Cie (France)
Louisiana Land and Exploration Company	Burlington Resources, Inc.
Magnum Hunter Production	Magnum Hunter Resources
Marathon Oil Company	USX Corporation
Mariner Energy	Mariner Energy, Inc.
Matrix Oil and Gas, Inc.	Matrix Oil and Gas, Inc.
Maxus US Exploration	Maxus US Exploration Company
McMoran Oil and Gas Company	McMoran Exploration Company
Murphy Exploration & Production	MurphyOil Corporation

Table 3-2 (cont.)

Company as listed in MMS, 1997 and 1999	Company listed by Corporate Parent
NCX Company, Inc.	NCX Company, Inc.
Newfield Exploration Company	Newfield Exploration Company
Nippon Oil Exploration USA, Inc.	Nippon Mitsubishi Oil Corporation
Norcen Explorer, Inc.	Union Pacific Resources Group, Inc.
Ocean Energy, Inc	Ocean Energy, Inc
Occidental Petroleum Corporation	Occidental Petroleum Corporation
Offshore Energy Development Corporation	Titan Exploration
Oryx Energy Company	Kerr McGee Corporation
Panaco, Inc	Panaco, Inc
Pel-Tex Oil Company	3Tec Energy Corporation
Pennzenergy	Devon Energy Corporation
Penzoil Exploration and Production Company	Devon Energy Corporation
Petrobras America, Inc.	Petroleo Brazileiro SA
Petroquest Energy, Inc.	Petroquest Energy, Inc.
Petsec Energy, Inc.	Petsec Energy, Inc.
Phillips Petroleum Company	Phillips Petroleum Company
Pioneer Natural Resources, Inc.	Pioneer Natural Resources, Inc.
Pogo Producing Company	Pogo Producing Company
Prime Natural Resources	Prime Natural Resources
Reading & Bates Development Company	R&B Falcon
Range Energy Ventures, Inc.	Range Resources Corporation
Ridgelake Energy	Ridgelake Energy
Samedan Oil Corporation	Noble Affiliates
SantaFe Energy Resources, Inc.	Santa Fe Snyder Corporation
Seagull Energy Exploration and Production, Inc.	Ocean Energy, Inc.
Seneca Resources Corporation	National Fuel Gas Company
Shell Deepwater Development, Inc.	Shell Oil Company
Shell Deepwater Production, Inc.	Shell Oil Company
Shell Offshore, Inc.	Shell Oil Company
SOCO Offshore, Inc.	SanteFe Synder Corporation
SONAT, Inc.	El Paso Energy Corporation
Spinnaker Exploration Company	Spinnaker Exploration Company
St. Mary Energy	St. Mary Land and Exploration Company
Statoil Exploration (U.S.), Inc.	Statoil Exploration (U.S.), Inc.
Stone Energy Corporation	Stone Energy Corporation
Tana Oil and Gas Corporation	TRT Holdings, Inc.
Tatham Offshore, Inc.	El Paso Energy Corporation
Taylor Energy Company	Taylor Energy Company
TDC Energy Corporation	TDC Energy Corporation
Texaco Exploration and Production, Inc.	Texaco, Inc.
Torch Operating Company	Torch Energy Advisors, Inc.
Total (France)	Total Fina Elf S.A.
Transworld Exploration and Production	Transworld Exploration and Production

Table 3-2 (cont.)

Company as listed in MMS, 1997 and 1999	Company listed by Corporate Parent
UMC Petroleum Corporation	Ocean Energy, Inc.
Union Pacific Resources Company	Union Pacific Resources Group, Inc.
Union Oil Company of California	Unocal Corporation
Vastar Resources, Inc.	BP Amoco Corporation (U.S.)
W&T Off shore, Inc.	W&T Off shore, Inc.
Walter Oil & Gas Corporation	Walter Oil & Gas Corporation
Westport Oil and Gas	Westport Oil and Gas
Westport Resources**	Westport Oil & Equitable Resources

* These mergers have taken place only as of January 2000.

** Equitable Production, a subsidiary of Equitable Resources, and Westport Oil and Gas pooled resources to form Westport Resources.

Table 3-3 shows the firms considered affected firms in the Gulf and their relevant 1999 financial data. These data include number of employees, assets, liabilities, and revenues, along with several ratios that provide a general indication of financial health. Note that blank lines in Table 3-3 indicate firms that are likely to be privately held and for which no public data are available.

Of these operators drilling in the Gulf, EPA has identified 40 (40 percent) that either meet the Small Business Administration's definition of a small business (which for the oil and gas extraction industry is defined as a business entity with 500 or fewer employees or for the oil field service industry as a business entity with $5 million or less in annual revenues) or that cannot be identified as large because their employment or revenue figures are not known. These latter firms might be privately owned, or they do not file with the SEC as an independent firm but their parent company could not be identified. The small and unknown-sized firms are discussed in more detail in Section Six, Regulatory Flexibility Analysis.

Table 3-3

Financial Data on Operators in the Gulf of Mexico ($1,000s)

Operator	Size	Type	Number of Employees	Assets	Equity	Revenues	Net Income	Return on Assets	Return on Equity	Profit Margin
3Tec Energy Corporation	Small	Independent	46	149,244	38,113	22,020	(3,432)	-2.3%	-9.0%	-15.6%
AEDC USA Inc	Large	Foreign	na	na	na	na	na	na	na	na
AGIP Petroleum Co Inc	Large	Foreign	na	na	na	na	na	na	na	na
Amerada Hess Corporation	Large	Major	8,485	7,727,712	3,038,192	7,461,354	437,616	5.7%	14.4%	5.9%
Anadarko Petroleum Corporation	Large	Major	1,431	4,098,363	1,534,554	701,104	42,579	1.0%	2.8%	6.1%
Apache Corp.	Large	Independent	1,429	5,502,543	2,669,427	1,300,505	200,855	3.7%	7.5%	15.4%
Apex Oil & Gas, Inc.*	Large	Independent	175	na	na	1,000,000	na	na	na	na
ATP Oil & Gas Corporation	Small	Independent	25	107,054	(3,655)	42,684	18,228	17.0%	-498.7%	42.7%
Aviva Petroleum Inc.	Small	Independent	61	8,986	(11,483)	7,053	(403)	-4.5%	3.5%	-5.7%
Barrett Resources Corp.	Small	Independent	202	884,301	363,648	1,004,781	20,828	2.4%	5.7%	2.1%
Basin Exploration Inc	Small	Independent	75	248,905	175,163	71,630	12,036	4.8%	6.9%	16.8%
Bellwether Exploration	Small	Independent	24	171,761	23,314	70,747	8,813	5.1%	37.8%	12.5%
BHP Petroleum (Americas) Inc	Large	Foreign	na	390,788	(1,658)	66,643	(72,183)	-18.5%	4353.6%	-108.3%
Bois d'Arc Operating Company	Large	Foreign	na	na	na	na	na	na	na	na
BP Amoco Corporation (U.S.)	Large	Major	na	27,348,000	na	38,786,000	2,018,000	7.4%	na	5.2%
British-Borneo Exploration Inc	Large	Foreign	na	na	na	na	na	na	na	na
BT Energy	Small	Independent	na	na	na	na	na	na	na	na
Burlington Resources Inc.	Large	Independent	1,997	7,191,000	3,246,000	2,065,000	1,000	0.0%	0.0%	0.0%
Cal Dive International, Inc.	Large	Independent	883	243,722	150,872	160,954	16,899	6.9%	11.2%	10.5%
Callon Petroleum Ltd.	Small	Independent	94	259,877	124,380	38,993	2,627	1.0%	2.1%	6.7%
Calpine Corporation*	Large	Independent	85	3,991,606	964,632	847,735	95,093	2.4%	9.9%	11.2%
Canadian Occidental Petroleum Ltd.	Large	Foreign	na	393,470	na	149,650	(1,460)	-0.4%	na	-1.0%
Century Exploration Company	Small	Independent	20	na	na	14,517	na	na	na	na
Century Offshore Management Corp.	Small	Independent	na	na	na	na	na	na	na	na
Challenger Minerals Inc.	Large	Foreign	na	26,900	na	8,300	2,000	7.4%	na	24.1%
Chateau Oil and Gas, Inc.	Small	Independent	na	na	na	na	na	na	na	na
Chevron Corp	Large	Major	36,490	40,668,000	17,749,000	36,586,000	2,070,000	5.1%	11.7%	5.7%

Table 3-3 (cont.)

Operator	Size	Type	Number of Employees	Assets	Equity	Revenues	Net Income	Return on Assets	Return on Equity	Profit Margin
Chieftan International, Inc.	Large	Independent	na	330,758	27,101	76,447	(6,897)	-2.1%	-25.4%	-9.0%
Cockrell Oil Corp.	Small	Independent	na	na	na	na	na	na	na	na
Conoco Inc	Large	Major	16,700	16,375,000	4,555,000	27,309,000	744,000	4.5%	16.3%	2.7%
Contour Energy Company *	Large	Independent	47	203,782	76,303	81,944	(9,733)	-4.8%	-12.8%	-11.9%
Davis Petroleum Corp.	Small	Independent	na	na	na	na	na	na	na	na
Devon Energy Corporation	Large	Independent	1,549	4,623,160	2,025,520	734,499	94,556	2.0%	4.7%	12.9%
Dominion Resources, Inc.	Large	Independent	11,035	17,747,000	4,752,000	5,520,000	296,000	1.7%	6.2%	5.4%
EEX Corporation*	Large	Independent	204	780,784	294,863	183,503	(87,797)	-11.2%	-29.8%	-47.8%
El Paso Energy Corp**	Large	Major	4,700	16,657,000	2,947,000	10,581,000	(255,000)	-1.5%	-8.7%	-2.4%
Energy Partners Ltd.*	Large	Independent	106	69,276	(3,815)	9,509	(2,284)	-3.3%	59.9%	-24.0%
Enron Corporation (Juniper)	Large	Major	17,900	33,381,000	9,570,000	40,112,000	893,000	2.7%	9.3%	2.2%
EOG Resources, Inc.	Large	Independent	775	210,793	1,129,611	801,406	569,094	270.0%	50.4%	71.0%
Equitable Resources, Inc.	Large	Independent	1,620	2,328,051	642,810	913,069	78,057	3.4%	12.1%	8.5%
Exxon Mobil Corporation	Large	Major	na	144,521,000	63,466,000	185,527,000	7,910,000	5.5%	12.5%	4.3%
Fairways Specialty Sales & Service	Small	Independent	na	na	na	na	na	na	na	na
Forcenergy, Inc.	Small	Independent	258	675,104	240,000	269,023	109,852	16.3%	45.8%	40.8%
Forest Oil Corp.	Small	Independent	272	800,052	318,984	357,258	19,043	2.4%	6.0%	5.3%
Global Industries	Large	Independent	1,894	755,935	398,178	387,452	(1,131)	-0.2%	-0.3%	-0.3%
Hall-Houston Oil Co.*	Large	Independent	25	na	na	28,171	na	na	na	na
Houston Exploration Co.*	Large	Independent	109	678,483	217,590	151,727	24,621	3.6%	11.3%	16.2%
Howell Corporation*	Large	Independent	118	117,983	20,680	48,428	(2,900)	-2.5%	-14.0%	-6.0%
Hunt Oil Company	Large	Independent	26,000	na	na	31,600	na	na	na	na
International Paper	Large	Independent	99,000	30,268,000	10,304,000	24,573,000	183,000	0.6%	1.8%	0.7%
JM Huber Corp.	Large	Independent	2,669	na	na	854,676	na	na	na	na
Kerr-McGee Corporation	Large	Major	3,653	5,899,000	1,492,000	2,696,000	142,000	2.4%	9.5%	5.3%
Linder Oil Co., A Partnership	Small	Independent	na	na	na	na	na	na	na	na
LLOG Exploration Offshore, Inc	Small	Independent	na	na	na	na	na	na	na	na
Magnum Hunter Resources	Small	Independent	89	306,110	53,640	69,626	(6,828)	-2.2%	-12.7%	-9.8%

Table 3-3 (cont.)

Operator	Size	Type	Number of Employees	Assets	Equity	Revenues	Net Income	Return on Assets	Return on Equity	Profit Margin
Mariner Energy Inc	Small	Independent	74	297,512	65,026	52,468	(9,970)	-3.4%	-15.3%	-19.0%
Matrix Oil & Gas, Inc.	Small	Independent	na	na	na	na	na	na	na	na
Maxus US Exploration Company	Large	Foreign	na	na	na	na	na	na	na	na
McMoran Exploration Company*	Large	Independent	213	301,281	155,071	244,031	109	0.0%	0.1%	0.0%
Meridian Resource Corp.	Small	Independent	94	477,719	163,860	133,361	16,867	3.5%	10.3%	12.6%
Murphy Oil Corporation	Large	Major	1,476	2,445,508	1,057,172	2,041,198	119,707	4.9%	11.3%	5.9%
National Fuel Gas Co.	Large	Independent	3,807	2,842,586	939,293	1,263,274	115,037	4.0%	12.2%	9.1%
NCX Company, Inc.	Small	Independent	na	na	na	na	na	na	na	na
Newfield Exploration Co.	Small	Independent	227	781,561	375,018	283,583	33,204	4.2%	8.9%	11.7%
Nippon Mitsubishi Oil Corporation	Large	Foreign	na	24,682,800	na	26,563,700	50,300	0.2%	na	0.2%
Noble Affiliates	Large	Independent	556	1,450,351	683,609	909,842	49,461	3.4%	7.2%	5.4%
Occidental Petroleum Corporation	Large	Independent	8,701	14,125,000	3,523,000	8,551,000	448,000	3.2%	12.7%	5.2%
Ocean Energy Inc	Large	Major	1,150	2,783,143	947,695	736,832	(43,838)	-1.6%	-4.6%	-6.0%
Panaco Inc	Small	Independent	34	135,438	(26,875)	42,927	(35,027)	-25.9%	130.3%	-81.6%
Petroleo Brazileiro SA	Large	Foreign	na	33,733,000	na	23,467,000	727,000	2.2%	na	3.1%
Petroquest Energy Inc.	Small	Independent	24	29,901	18,105	8,607	(310)	-1.0%	-1.7%	-3.6%
Petsec Energy, Inc.	Small	Independent	23	93,508	(71,313)	31,260	(29,488)	-31.5%	41.4%	-94.3%
Phillips Petroleum Company	Large	Major	15,900	15,201,000	4,549,000	13,852,000	609,000	4.0%	13.4%	4.4%
Pioneer Natural Resources, Inc.	Large	Independent	817	2,929,473	774,614	710,135	(22,460)	-0.8%	-2.9%	-3.2%
Pogo Producing Co.	Small	Independent	165	949,401	268,512	275,116	22,134	2.3%	8.2%	8.0%
Prime Natural Resources	Small	Independent	20	na	na	2,200	na	na	na	na
R & B Falcon	Large	Independent	5,100	4,916,100	1,204,400	919,000	103,000	2.1%	8.6%	11.2%
Range Resources Corp.	Small	Independent	136	752,368	127,171	201,364	(7,793)	-1.0%	-6.1%	-3.9%
Ridgelake Energy	Small	Independent	na	na	na	na	na	na	na	na
S.A. Louis Dreyfus et Cie	Large	Foreign	na	na	na	na	na	na	na	na
Santa Fe Snyder Corporation	Large	Independent	1,408	1,862,800	741,200	511,400	(124,900)	-6.7%	-16.9%	-24.4%
Shell Oil Company	Large	Major	19,800	26,111,000	11,483,000	19,277,000	1,903,000	7.3%	16.6%	9.9%
Spinnaker Exploration Company	Small	Independent	35	189,553	177,102	34,786	(1,337)	-0.7%	-0.8%	-3.8%

Table 3-3 (cont.)

Operator	Size	Type	Number of Employees	Assets	Equity	Revenues	Net Income	Return on Assets	Return on Equity	Profit Margin
Statoil Exploration US Inc	Large	Foreign	na	20,983,500	na	17,822,800	435,900	2.1%	na	2.4%
Stone Energy Corp.	Small	Independent	103	441,738	265,587	149,134	(26,490)	-6.0%	-10.0%	-17.8%
St.Mary Land and Exploration Co.	Small	Independent	142	230,438	188,772	75,029	82	0.0%	0.0%	0.1%
Taylor Energy Co.	Small	Independent	na	na	na	na	na	na	na	na
TDC Energy Corp.	Small	Independent	na	na	na	na	na	na	na	na
Texaco Inc	Large	Major	18,443	28,972,000	12,042,000	35,691,000	1,177,000	4.1%	9.8%	3.3%
Titan Exploration, Inc.	Small	Independent	76	268,798	160,851	75,717	(8,274)	-3.1%	-5.1%	-10.9%
Torch Energy Advisors Inc.	Large	Independent	1,804	na	na	57,000	na	na	na	na
Total Fina Elf S.A.	Large	Foreign	127,525	80,415,000	na	70,337,800	3,277,200	4.1%	na	4.7%
Trasnworld Exploration and Production	Small	Independent	na	na	na	na	na	na	na	na
TRT Holdings, Inc.	Large	Independent	na	na	na	na	na	na	na	na
Union Pacific Resources Group Inc	Large	Major	2,202	6,146,900	937,500	1,727,500	225,800	3.7%	24.1%	13.1%
UNOCAL Corporation	Large	Independent	7,550	8,967,000	2,184,000	6,057,000	137,000	1.5%	6.3%	2.3%
USX Corporation	Large	Independent	51,003	22,962,000	6,853,000	29,583,000	698,000	3.0%	10.2%	2.4%
W & T Offshore, Inc.	Small	Independent	57	na	na	50,000	na	na	na	na
Walter Oil & Gas Corporation*	Large	Independent	33	na	na	50,000	na	na	na	na
Westport Resources	Small	Independent	94	271,477	140,011	73,763	(3,126)	-1.2%	-2.2%	-4.2%
Maximums			99,000	144,521,000	63,466,000	185,527,000	7,910,000	270%	50%	71%
Minimums			23	8,986	(71,313)	7,053	(255,000)	-32%	-30%	-108%
Totals			350,709	495,307,687	182,514,345	474,360,421	18,885,597	286%	277%	-98%
Medians (based on individual companies' figures)			414	800,052	375,018	387,452	18,228	2%	6%	3%

Source: Oil & Gas Journal. OGJ 200, 2000; Pennwell Petroleum Directory, 1998; SEC's Edgar Database at http:\\www.sec.gov.; Hoovers Online at http://www.hoovers.com; and Lycos Companies Online at http://www.companiesonline.com.

* Considered large on the basis of industry designation and revenues (oil and gas service industry is designated small on the basis of revenues greater than five million dollars per year).

** The Coastal Corporation and El Paso Energy Corporation announced a merger agreement in January 2000. Although El Paso's financial statements for 1999 do not reflect the merger, in this analysis the two corporations are considered to be one entity.

Note that operators owned by foreign firms are assumed to be large, even when data on employment could not be found, for the following reasons. First, SBA defines a small business as one "with a place of business in the United States, and which operates primarily in the United States or which makes a significant contribution to the economy" (13 CFR Part 121). EPA assumes that if the U.S. firm is foreign-owned, it would not meet these criteria. Second, the parent corporation most likely would not meet the size criteria. Multinational foreign firms operating in the United States typically operate in many other locations throughout the world and thus would generally require a workforce in excess of 500 persons.

Financially, the potentially affected operators are a healthy group of firms. Table 3-4 presents summary financial statistics for the large and small firms. Due to a relatively hard year for the oil and gas industry, among publicly held firms, median return on assets for the group is 2 percent, median return on equity is 6 percent, and median profit margin (net income/revenues) is 3 percent, according to 1999 financial data. In the oil and gas industry, financial health varies as swiftly as oil prices. In 1999, the average domestic first purchase price was $15.56/bbl and the wellhead price for gas was $2.08/Mcf. In the first seven months of 2000, oil prices averaged $25.50/bbl and gas prices averaged $2.82/Mcf (DOE, 2000). The financial health of the oil firms should show a corresponding increase.

3.2.4 Estimates of Drilling Activity

EPA has not revised its estimates of drilling activity in the Gulf since proposal. Table 3-5 presents data from MMS on drilling activity in 1995, 1996, and 1997 by type of drilling and by depth. In addition to showing an annual increase in the number of wells drill, the table indicates that most wells drilled in the Gulf of Mexico Federal OCS are development wells drilled in less than 1,000 feet of water. Exploratory drilling in waters less than 1,000 ft. deep also makes up a major portion of wells drilled annually. Based on the MMS data, an average of 1,119 wells were drilled annually in the Federal OCS during the 1995 - 1997 time frame.

Table 3-4

Minimum, Median, and Maximum Financial Data for Large and Small Firms ($1,000s)

	Number of Employees	Assets	Equity	Revenues	Net Income	Return on Assets	Return on Equity	Profit Margin
Small firms								
Minimum	23	8,986	(71,313)	7,053	(35,027)	-32%	-15%	-94%
Median	89	268,798	140,011	71,630	(310)	-1%	0%	-4%
Maximum	272	949,401	375,018	1,004,781	109,852	17%	46%	43%
Large firms								
Minimum	47	69,276	(3,815)	9,509	(255,000)	-18%	-30%	-108%
Median *	1584.5	4,360,762	1,167,006	1,091,137	99,047	2%	9%	4%
Maximum	99000	144,521,000	63,466,000	185,527,000	7,910,000	270%	50%	71%
All firms								
Minimum	23	8,986	(71,313)	7,053	(255,000)	-32%	-30%	-108%
Median *	501	800,052	375,018	387,452	18,228	2%	6%	3%
Maximum	99,000	144,521,000	63,466,000	185,527,000	7,910,000	270%	50%	71%

Source: Oil & Gas Journal. OGJ 2000; Pennwell Petroleum Directory, 1998; SEC's Edgar Database at http://www.sec.gov; Hoovers Online at http://www.hoovers.com; and Lycos Companies Online at http://www.companiesonline.com

* Used hypothetical number (501) for employees for larger firms when number of employees was not available.

Table 3-5

Number of Wells Drilled in the Gulf of Mexico OCS and Texas Where Controlled Discharge of Drilling Fluids and Cuttings Is Allowed

Year	Shallow Water Wells (<1,000 feet)		Deep Water Wells (>1,000 feet)		Total Wells
	Development	Exploratory	Development	Exploratory	
1995	577	314	32	52	975
1996	617	348	42	73	1,080
1997	726	403	69	104	1,302
Annual Average OCS	640	355	48	76	1,119
Estimated Wells Drilled 3 Miles to 3 Leagues Offshore TX	5	3	0	0	8
Total Annual Estimate	645	358	48	76	1,127

Source: MMS TIMS data and personal communication with RRC (James Covington, EPA, and Donna Burks, RRC, Sept. 1, 1998).

Data on wells drilled in the state waters off Texas in the 3 miles to 3 leagues area are not included in the MMS count, but the Railroad Commission of Texas (RRC) indicated that 10 wells were drilled in 1996, 5 in 1997, and 9 so far in 1998 in the Texas offshore region (which includes everything offshore, including less than 3 miles from shore) or an average of 8 wells per year (communication between James Covington, EPA, and Donna Burks, RRC, September 1, 1998).[5] When this number of wells is added to the OCS numbers, EPA calculates an average of 1,127± wells are drilled per year in the Gulf.

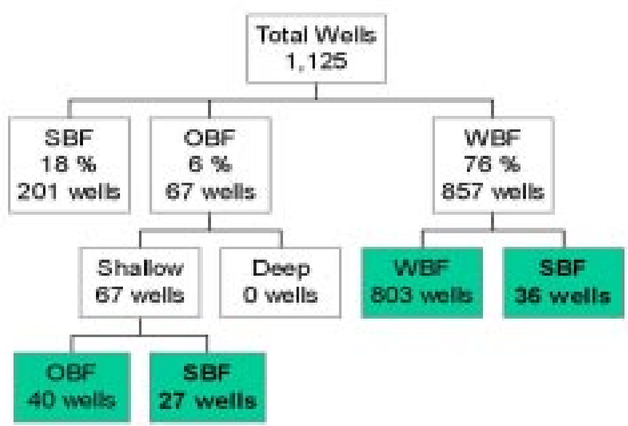
EPA worked with industry to estimate the percentage of wells drilled with each type of fluid (WBF, OBF, or SBF) prior to the regulation as well as the percentage of WBF or OBF wells that would switch to SBF after the regulation. EPA estimates that almost 18 percent, or 201 wells, are drilled currently with SBFs and 6 percent, or 67 wells, are drilled with OBFs. EPA further estimates that no OBFs are used in

[5]These are not NPDES CWA permits, but permits issued by the state of Texas.

deep water drilling, and of the 67 OBF wells estimated to be drilled annually in shallow water, 39 percent, or 27 wells, would convert to using SBFs if discharge of SBF-cuttings was allowed. The remaining 857 wells that are estimated to be drilled annually in the Gulf of Mexico are assumed to be drilled exclusively using WBFs. Of these, 36 wells or 4 percent, would convert to using SBFs if discharge of SBF-cuttings was allowed because of the quicker drilling times and greater ability to drill directional wells (see Development Document). Due to rounding, the total number of wells is 1,125 prior to the regulation. See Figure 3-1 for a summary of the breakdown and the SBF Development Document for details.

Figure 3-1

Breakdown of Wells by Drilling Fluid Type
BAT Gulf of Mexico Wells



Note: Unshaded boxes reflect current distribution of wells.
Shaded boxes show changes after BAT 1 or BAT 2.
Because of increased drilling efficiencies, 54 WBF wells are replaced by 36 SBF wells.

3.3 OVERVIEW OF DEEPWATER OIL AND GAS DRILLING AND PRODUCTION IN THE GULF OF MEXICO

Offshore production in the Gulf of Mexico began in 1949 with a shallow well drilled in shallow water. It took another 25 years until the first deepwater well ($\geq$1,000 ft. of water) was drilled in 1974. Barriers to deepwater activity include technological difficulties of stabilizing a drilling rig in the open ocean, high financial costs, and natural and manmade barriers to oil and gas activities in the deep waters.

These barriers have been offset in recent years by technological developments (e.g., 3-D seismic data covering large areas of the deepwater Gulf and innovative structure designs) and economic incentives (see Section 3.3.1). As a result, deepwater oil and gas activity in the Gulf of Mexico has dramatically increased from 1992 to 1999. In fact, in late 1999, oil production from deepwater wells surpassed that produced from shallow water wells for the first time in the history of oil production in the Gulf of Mexico.

MMS has been actively tracking these developments and proactively evaluating the potential effects of exploration, drilling, and production activities in the deepwater Gulf. The profile presented here draws heavily on the MMS report *Deepwater Gulf of Mexico: America's Emerging Frontier* (MMS, 2000a). MMS also performed an environmental assessment of deepwater operations and activities in which it found a potentially significant localized impact to chemosynthetic communities (e.g., tube worms) from the discharge of SBF and cuttings wetted with SBF under baseline conditions (MMS, 2000b). As a result of this assessment, MMS developed a mitigation measure requiring deepwater wells to be at least 1,000 feet away from any potential high-density chemosynthetic community. On the other hand, MMS noted that zero discharge of SBF cuttings could increase the use of oil-based fluids (a scenario modeled in the cost analysis) with a concomitant increase in water quality problems currently being faced at some commercial onshore disposal sites (MMS, 2000b).

The section begins with a discussion of the Outer Continental Shelf Deep Water Royalty Relief Act (Section 3.3.1) because it is a major underlying factor in the dramatic increase in oil and gas activity in this region. The subsequent sections follow the sequence in oil and gas development—leasing, drilling, development, and reserves and production.

3.3.1 Deep Water Royalty Relief Act

The Outer Continental Shelf Deep Water Royalty Relief Act (hereafter called the "Act") had a large impact on deepwater activity in the Gulf (43 U.S.C. §1337). The Act provides economic incentives to operators drilling in waters with a depth of more than 200 meters (656 feet). Federal royalty payments are waived for deepwater leases acquired between November 28, 1995 and November 28, 2000. The extent of the waiver is determined according to the depth of the water and the production volume (million barrels of oil equivalent [MMBOE] drilled):

- For a field in 200 to 400 meters (656 to 1312 feet) of water, royalty payments are waived for the first 17.5 MMBOE produced,
- For a field in 400 to 600 meters (1312 to 2624 feet) of water, royalty payments are waived for the first 52.5 MMBOE produced, and
- For fields in greater than 800 meters (2,624 feet) of water, royalty relief is provided for up to 87.5 MMBOE.

The Act also has provisions that allowed reductions in royalty payments for fields leased prior to 1995. Throughout Section 3.3, tables with times series data have a dotted line between 1995 and 1996 to highlight the increased activity resulting from the Act.

3.3.2 Leasing

Because of the significant economic incentives offered by the Act, companies became more interested in the deepwater Gulf. One side effect of the Act was a dramatic increase in the acquisition of 3-D seismic data. Sound waves are transmitted to and through the ocean bottom and are reflected back according to the geological layers in the earth. Recent advances in computer technology allow the detailed analysis of these 3-dimensional "cubes" to identify likely oil and gas accumulations. This technology reduces the risk in exploration and, therefore, the financial risk associated with exploration and production.

Table 3-6 shows the number of leases issued in the Gulf of Mexico per year from 1992 to 1999. Although leasing activity had been on the rise since 1992, the Act accelerated leasing activity in deepwater from 1996 to 1999. The number of leases issued are divided into four water-depth categories. As can be seen from the table, the largest increase in leases from 1995 to 1999 is in areas with water depths greater than 800 meters, which is the category with the largest royalty relief.

Table 3-6

Number of Leases Issued in the Gulf of Mexico 1992 - 1999

Year	Number of Leases in Water Depth Categories (meters)			
	Less than 200m	**200 to 400m**	**400 to 800m**	**More than 800m**
1992	176	4	17	7
1993	261	15	36	24
1994	466	25	30	39
1995	509	52	103	171
1996	620	66	110	712
1997	525	44	99	1,110
1998	265	35	58	771
1999	165	16	17	135
Total	**2,987**	**257**	**470**	**2,969**

Source: MMS, 2000a.

In 1992, industry held 5,600 active leases in the Gulf of which 27 percent were in deep water (~1,500 leases). By 1999, industry held 7,600 active leases of which 48 percent are in deep water (~3,800 leases).[6] That is, the deepwater region is showing nearly twice the growth in activity than the shallow water region of the Gulf. The number of leases issued for fields in greater than 800 meters decreased from 1998 to 1999, possibly due to the lower oil prices during that period. It is important to note that there is a

[6] Lease statuses may change daily, so the current number of active leases is an approximation. The total number of leases in Table 3-6 exceeds the number of active leases held in 1999 because of lease expirations. Leases for blocks in less than 400 meters of water are 5 years in length, 8 years for blocks in 400 to 799 meters of water, and 10 years for blocks in 800 meters of water or deeper.

considerable time lag between leasing, qualification, and production. Hence, the ultimate impact of the Act will not be achieved for a few years.

Not only did the number of deepwater leases issued increase drastically from 1995 to 1998, the financial investment also increased dramatically. The total amount of money bid for deepwater leases was at an all time high in 1997—$500 million for fields 5,000 to 7,500 feet deep.

The ownership of leases in the deep waters of the Gulf of Mexico also has seen changes in the last five years. Although deepwater leases were dominated by majors from 1992 through 1995, beginning in 1996, independents began to acquire significant deepwater lease holdings.[7] In 1995, independents held 186 deepwater leases. By 1999, independents held 1,371 leases—a seven-fold increase in four years. Since there may be substantial lag times between leasing and production, independents may show a surge in production in future years.

3.3.3 Exploration and Development Drilling

3.3.3.1 Drilling Activity

There have been significant increases in exploration and development activities in the Gulf over the past decade. Table 3-7 shows the number of deepwater exploration and development plans approved by MMS between 1992 and 1999. There are two primary types of drilling operations in oil and gas extraction—exploratory and developmental. While exploratory drilling is undertaken to determine potential reserves, developmental drilling takes place for production purposes. In order to proceed with deepwater drilling projects, operators first file a Plan of Exploration (POE) with MMS. After drilling exploratory wells, the operators can then file a conceptual Deep Water Operations Plan (DWOP). Following this, a Development Operations Coordination Document (DOCD) is filed. Developmental wells can then be

[7] Majors active in the Gulf include Arco, BP Amoco, Chevron, Exxon Mobil, Shell, and Texaco. Mergers between some of these players also has affected lease ownership and the diversity of lease ownings. For instance, the merger between BP Amoco and Arco had a significant impact on the dominance of this combined corporation in this arena.

drilled, but production cannot begin until a final DWOP is filed. As can be seen from the table, the number of exploration plans increased steadily over the last eight years. The number of DOCDs and DWOPs approved also has increased.

Table 3-7

Number of Deepwater Plans Approved by MMS in the Gulf of Mexico 1992 - 1999

Year	Number of Plans Approved by MMS		
	Plan of Exploration	Development Operations Coordination Document	Deep Water Operations Plan
1992	24	3	-
1993	21	3	-
1994	33	4	-
1995	34	8	5
1996	62	4	19
1997	85	13	30
1998	124	13	16
1999	143	16	18
Total	**526**	**64**	**88**

Source: MMS, 2000a.

Not only has the submission of deepwater drilling plans increased, but actual deepwater exploratory and developmental drilling has seen increasing levels of activity between 1992 and 1998. The number of exploratory wells drilled increased steadily from 1992 to 1998 and then slowed in 1999. In 1992, less than ten exploratory wells were drilled; whereas in 1998, more than a hundred wells were drilled. The largest increase in exploratory well drilling was seen in the 1,500- to 5,000-foot depth category. There were also significant increases in drilling of wells in water depths ranging from 5,000 to 7,500 feet. Similarly for developmental drilling, this activity also has increased between 1992 and 1997, most dramatically in the 1,500- to 5,000-foot water depth range. In 1998 and 1999, developmental drilling decreased slightly, however.

In the offshore, well depth may be measured in several ways, two of which are true vertical depth (the vertical distance, in feet, from the rig kelly bushing to the maximum depth of the well) and water depth. As mentioned in the beginning of this section, offshore production began in 1947 with a shallow well (<3,000 feet) in shallow water (~100 feet). The next year, the deepest offshore well had a true vertical depth of 13,600 feet but little change in water depth. Maximum true vertical depth gradually doubled over 50 years (i.e., from 13,600 feet in 1949 to 27,000 in 1998). The change in maximum water depth drilled is much more striking. It took nearly 30 years for the industry to drill in water deeper than 1,000 feet. (In 1974, the maximum water depth drilled was 1,024 feet). After that, change was quite rapid. Two years later, in 1976, industry nearly doubled the water depth drilled record (1,986 feet). In 1984, industry reached 3,534 feet. Three years later, in 1987, industry doubled its last milestone by drilling in water depths exceeding 7,500 feet. The current record is only slightly deeper at 7,716 feet.

3.3.3.2 Drilling Rig Availability

Table 3-8 lists the average number of rigs drilling in the deepwater Gulf from 1992 to 2001. The number of rigs increased nine-fold or 800 percent from 3 in 1992 to 27 in 1999. However, not all drilling rigs can drill in all depths. MMS (2000a) estimates there are about 45 rigs in the Gulf capable of drilling deepwater wells:

- 5 rigs can drill in water depths up to 1,499 feet
- 22 rigs have maximum depth capacities between 1,500 to 4,999 feet
- 14 rigs have maximum depth capacities between 5,000 to 7,499 feet, and
- 4 rigs have maximum depth capacities 7,500 feet or greater.

There are 470 active leases in water depths of 7,500 feet or greater and only 4 rigs capable of drilling at these water depths. Approximately 15 ultra-deep rigs are under construction, but the Gulf region will need to compete for their services with other areas of the world. Even though not all leases will be drilled, there is the potential for some constraint on evaluation of deepwater leases due to rig availability (or lack thereof).

Table 3-8

Average Number of Rigs Drilling in the Deepwater Gulf of Mexico: 1992 - 2001

Year	Average Number of Rigs
1992	3
1993	6
1994	11
1995	14
1996	18
1997	26
1998	28
1999	27
2000 (estimated)	30
2001 (estimated)	31

Source: MMS, 2000a.

3.3.4 Development

There are several types of deepwater development systems producing oil and gas in the Gulf of Mexico. These are:

- Fixed platforms with water depth capacities of 1,200 to 1,500 feet
- Compliant towers used in water depths ranging from 1,000 to 3,000 feet
- Tension leg platforms for fields in 1,000 to 5,000 feet of water
- Spars and other floating systems used for water depths greater than 8,000 feet
- Subsea systems also used in greater than 8,000 feet of water

Table 3-9 lists deepwater discoveries by prospect or field name, the operators, location, water depth, discovery date, production start-up date, and the development system.

Subsea systems have played an important role in the increase of deepwater drilling and production. These systems are submerged drilling facilities resting on the sea bottom. They are used in both shallow and deep water and have flowlines connecting to a “host” facility on the surface. Table 3-10 shows the number of subsea completions for the shallow and deep water each year from 1992 to 1999. From 1996 through 1999, 83 subseabed installations were completed. The past four years, then, account for nearly half of all subseabed completions (186) recorded by MMS.

Subseabed completions show a similar pattern to wells with a the recent rapid increase in maximum water depth. Until 1987, no subseabed completion was in water deeper than 350 feet. In 1988, the record depth jumped to 2,200 feet. From 1989 though 1996, maximum water depths for subseabed completions increased to nearly 3,000 feet but jumped to a depth of 5,295 feet in 1997. The distance from the subseabed completion to its host facility may be as long as 63 miles (Mensa to West Delta block 143) but most are less than 15 miles long.

One type of deepwater development system not currently used in the Gulf of Mexico is a floating, storage, production, and off-loading system (FPSO). These systems are used in 1,000 to greater than 8,000 feet of water and include processing and storage facilities. At present, the MMS is assessing the environmental impacts of introducing FPSO systems in the Gulf of Mexico.

To support the increasing number of subsea systems in the Gulf of Mexico, the length and diameter of pipelines taking the hydrocarbons to a service base have also been on the rise. The miles of pipeline greater than 12 inches in diameter approved has risen from approximately 40 miles in 1996 to almost 300 miles in 1999.

Table 3-9

Deepwater Production and Discoveries

Prospect Name	Operator (Partners)	Area/Blk	Water Depth (ft)	Discovered	Production Start-up Date (estimated)	Platform/System Type
Alabaster	Exxon (EEX, Walter)	MC 397	1,059	1984	1992	Fixed
Allegheny	British-Borneo	GC 254	3,186	1996	1999	TLP/subsea
Amberjack	BP Amoco (Shell, Conoco)	MC109	1,029	1986	1991	Fixed
Angus	Shell (Marathon)	GC 113	2,045	1997	1999	Subsea
Anstey (East)	BP Amoco	MC 607	6,680		1999	Subsea
Arnold	Marathon	EW 963	1,800		1998	Subsea
Atlantis	BP Amoco (BHP)	GC 699	6,133	1998		
Auger	Shell (BP Amoco)	GB 426	2,860	1987	1994	TLP
Baldpate	Amerada Hess	GB 260	1,641	1991	1998	Compliant Tower
Bison	Exxon	GC 166	2,518			
Black Widow	Mariner	EW 966	1,850	1998		Subsea
Boomvang (East)	Reading & Bates	EB 688	3,737	1988		
Boomvang (North)	Reading & Bates (Norcen)	EB 643	3,688	1997		
Brutus	Shell (Exxon)	GC 158	2,877	1989	2001	TLP
Bullwinkle	Shell	GC 62	1,353	1983	1989	Fixed
Cognac	Shell	MC 194	1,025	1976	1979	Fixed
Conger	Amerada Hess (Shell, Kerr-McGee)	GB 215	1,500	1998	2000	Subsea

Table 3-9 (cont.)

Prospect Name	Operator (Partners)	Area/Blk	Water Depth (ft)	Discovered	Production Start-up Date (estimated)	Platform/System Type
Cooper	EEX (EP Operating)	GB 388	2,190	1989	1995	FPS
Coulomb	Shell	MC 657	7,500	1988		
Crazy Horse	BP Amoco	MC 777,	6,050	1999		
Crosby	BP Amoco	MC 899	4,452			
Diamond	Kerr-McGee	MC 445	2,095	1988	1994	Subsea
Diana	Exxon (BP Amoco)	EB 945	4,500	1991	2000	Spar
Diana (South)	Exxon	AC 65	4,800	1996	2000	Subsea
Dulcimer	Mariner	GB 367	1,120	1998	1999	Subsea
Europa	Shell (BP Amoco, Conoco)	MC 935	3,870	1994	2000	Subsea
EW 1006	Walter	EW 1006	1,884	1997	1998	Subsea
Fuji	Texaco (Statoil)	GC 506	4,243	1995	2001	FPSO
GB 254	Chevron	GB 254	1,920			
GC 72	Mobil	GC 72	1,655			Subsea
GC 228	Texaco	GC 228	1,638			
Gemini	Texaco (Chevron)	MC 292	3,393	1995	1999	Subsea
Genesis	Chevron (Exxon, Fina)	GC 205	2,597	1996	1998	Spar
Glider	Shell	GC 248	3,300	1996	2000	TLP
Gomez	Union Pacific	MC 755	3,000	1997	2001	Spar or TLP
Grand Canyon	Conoco	GC 141	1,715			

Table 3-9 (cont.)

Prospect Name	Operator (Partners)	Area/Blk	Water Depth (ft)	Discovered	Production Start-up Date (estimated)	Platform/System Type
Habanero	Shell (Murphy, Callon)	GB 341	2,000	1999		
Herschel(part of Nakika?)	Shell / BP Amoco	MC 522		1997 ?	2003	Subsea
Holstein	BP Amoco	GC 644,	4,390	1998		
Herschel South	Shell / BP Amoco	MC 520	6,739	1997	2003	Subsea
Hoover	Exxon (BP Amoco)	AC 25, 26	4,785	1997	2000	Spar
Jolliet	Conoco	GC 184	1,720	1981	1989	TLP
King	BP Amoco	MC 84	5,500	1993	2001	Subsea
King	Shell (Vastar, BP Amoco)	MC 764	3,250	1997	2000	Subsea
King Kong	Conoco (Shell, BBEI)	GC 472	3,817	1997	2000	Subsea
King's Peak	BP Amoco	DC 133	6,530	1993	2001	Subsea
Knight	Santa Fe	GB 372	1740			
Ladybug	Texaco (UNOCAL)	GB 409	1,355	1997		
Lena	Exxon	MC 281	1,018	1976	1983	Guyed Tower
Leo	British-Borneo (Shell)	MC 502,503, 546	2,500			
Llano	EEX	GB 386	2,300		1999	Subsea
MC 26	BP Amoco	MC 26	1,272			
MC 243	Conoco (Kerr-McGee)	MC 243	3,100		2000	

Table 3-9 (cont.)

Prospect Name	Operator (Partners)	Area/Blk	Water Depth (ft)	Discovered	Production Start-up Date (estimated)	Platform/System Type
MC 441	EEX (Agip, Fina)	MC 441	1,520	1986	1993	Subsea
MC 443	Walter	MC 443	2,095		1999	Subsea
MC 533	Walter	MC 533	1,000		1999	Subsea
MC 837	Walter	MC 837	3,900		1999	Subsea
Macaroni	Shell	GB 602	3,600	1995	1999	Subsea
Mad Dog	BP Amoco	GC 826	6,560	1998		
Marlin	BP Amoco	VK 915	3,236	1993	1999	TLP
Mars	Shell (BP Amoco)	MC 807	2,940	1989	1996	TLP/Subsea
Marshall	Exxon	EB 948,	4,500			
Mensa	Shell	MC 687	5,376	1987	1997	Subsea
Metallica	BP Amoco	MC 911	7,000		2004	
Mica	Exxon (BP Amoco)	MC 211	4,356	1990	2001	Subsea
Mirage	Vastar	MC 941	3,927	1999		Subsea
Morgus	Shell	MC 942	3,960	1998	2002	
Morpeth	British-Borneo	EW 965	1,630		1998	TLP/Subsea
Mosquito Hawk	Texaco	GB 269	1,102			
Nakika	Shell / BP Amoco	MC 383	5,759	1997	2000	Monohull FPS
Narcissus	Texaco	MC 630	4,250	1997		
Neptune	BP Amoco (BHP)	AT 574	6,220		2001	

Table 3-9 (cont.)

Prospect Name	Operator (Partners)	Area/Blk	Water Depth (ft)	Discovered	Production Start-up Date (estimated)	Platform/System Type
Neptune	Kerr-McGee (CNG)	VK 826	1,930		1997	Spar
Nile	BP Amoco	VK 914	3,535	1997	2001	Subsea
Nirvana	BP Amoco	MC 162	3,414		2001	
Oyster	Marathon (Texaco)	EW 917	1,200	1996	1998	Subsea
Penn State	Amerada Hess (Kerr-McGee)	GB 216	1,450	1996	1998	Subsea
Petronius	Texaco (Marathon)	VK 786	1,754	1995	2000	Compliant Tower
Pluto	Mariner / BP Amoco (Burlington)	MC 718	2,828		2000	Subsea
Pompano I	BP Amoco (Kerr-McGee)	VK 989	1,290	1985	1994	Fixed
Pompano II	BP Amoco (Kerr-McGee)	MC 28	1,865	1985	1995	Subsea
Popeye	Shell (CNG, Mobil, BP Amoco)	GC 116	2,000	1985	1996	Subsea
Poseidon	BP	GC 691	4,489			
Prosperity	Texaco	VK 742	1,000	1998		
Ram-Powell	Shell (Exxon, BP Amoco)	VK 956	3,214	1989	1997	TLP
Rocky	Shell	GC 110	1,785	1994	1996	Subsea
Salsa	Amerada Hess	GB 171	1,076			

Table 3-9 (cont.)

Prospect Name	Operator (Partners)	Area/Blk	Water Depth (ft)	Discovered	Production Start-up Date (estimated)	Platform/System Type
Seattle Slew	Tatham	EW 914	1,019	1991	1993	Subsea
Shasta	Texaco (Mariner)	GC 136	1,040	1994	1995	Subsea
Sorano	Shell	GB 516	3,153		2001	Subsea
Spirit	Shell	VK 780	1,040		1998	Fixed
Stellaria	Shell (Marathon)	GC 112	2,045		1999	Subsea
Sunday Silence	Flextrend	EW 958	1,450	1994	2001	MiniTLP
Tahoe	Shell (Murphy)	VK 783	1,500	1984	1994	Subsea
Thor	Kerr-McGee	VK 825	1,720		1998	Subsea
Toro	Shell	GC 69	1,465		2000	
Troika	BP Amoco (Shell, Marathon)	GC 244	2,721	1994	1997	Subsea
Ursa	Shell (BP Amoco, Conoco, Exxon)	MC 809	3,916	1991	1999	TLP
VK 862	Walter	VK 862	1,043		1995	Subsea
Virgo	Elf Exploration	VK 823	1,130	1997	1999	Fixed
Zeus	Exxon	MC 941	3,905			
Zinc	Exxon	MC 354	1,478	1977	1993	Subsea

Notes: Shaded areas indicate producing prospects.
Data as of August 1999.

Source: Regg, 1999.

Table 3-10

Number of Subsea Completions in the Gulf of Mexico: 1992 - 1999

Year	Number of Subsea Completions	
	Shallow Water	Deep Water
1992	1	2
1993	3	11
1994	7	1
1995	10	4
1996	12	10
1997	13	7
1998	8	9
1999	10	14
Total	64	58

Source: MMS, 2000a.

Finally, increasing exploration and production of oil and gas from the deep waters means more infrastructure has been put in place onshore to support these activities. Although service bases already existed in southeast Louisiana, the increased deepwater activity has spread service bases to southwest Louisiana and Texas.

3.3.5 Reserves

Deepwater discoveries are accounting for an increasing proportion of reserves. There are four kinds of reserves in the oil and gas industry: proved reserves, unproved reserves, known resources, and industry-announced discoveries. Proved reserves are those that are considered recoverable and are currently producing. Unproved reserves are potentially recoverable reserves with no current or near-future production. Known resources are discovered sources with lower possibilities of production. Finally, industry-announced discoveries are those made by operators but not evaluated by MMS.

The number of proved reserve additions from the shallow waters peaked in 1967 and has declined every decade thereafter. In contrast, the number of deepwater proved reserves has increased significantly since 1975. More importantly, the average size of a deepwater field is far greater than that of a shallow water field. In the 1990s, an average deepwater field added proven and unproven reserves (47 MMBOE) that were nine times the proved and unproved reserves of an average shallow water field (5 MMBOE). In the most active depth range (1,500 to 7,499 feet), the field sizes average 60 MMBOE. This implies that the deepwater regions hold the potential for many large fields.

The number of deepwater field discoveries also has been on the rise, especially from 1993 to 1997. The number of producing fields on the other hand, has not increased that significantly. This can be partly explained by the time lag between the discovery of a field and when actual production begins.

Table 3-11 displays the number of discoveries, including proved, unproved, known resources, and industry-announced discoveries, that have occurred each year since 1975. The trend spells out an increasing number of discoveries from 1992 to 1997. When taking into consideration the additions of oil and gas reserves contributed by deepwater discoveries, it is clear that, in the last decade or so, the deepwater discoveries have added large amounts of reserves to the Gulf of Mexico and have the promise to do so in the near future as well.

3.3.6 Production

Although there is a time lag between discovery and production, production from deepwater wells in the Gulf of Mexico has been steadily and significantly increasing since 1985. Deepwater production in the Gulf increased 321,000 barrels per day between 1994 and 1998.

Table 3-12 shows deepwater oil and gas production as a percentage of total production in the Gulf as well as the year-to-year percentage increase in deepwater oil and gas production. Deepwater oil and gas

Table 3-11

Number of Deepwater Discoveries Including Proved, Unproved, Known, and Industry Announced Discoveries: 1975 - 1999

Year	Number of Discoveries	Year	Number of Discoveries
1975	1	**1990**	4
1976	3	**1991**	4
1977	1	**1992**	1
1981	3	**1993**	4
1983	1	**1994**	5
1984	12	**1995**	7
1985	7	**1996**	7
1986	6	**1997**	9
1987	8	**1998**	11
1988	5	**1999**	3
1989	7		

Source: MMS, 2000a.

production has been forming a larger and larger percentage of total production in the Gulf through time. The impact of the Deep Water Royalty Relief Act is apparent. In 1995, deepwater oil and gas formed 16 and 4 percent of production from the Gulf, respectively. In 1999, 45 percent of oil and 17 percent of gas produced in the Gulf were from deepwater projects. Note also that the year-to-year percentage increase in deepwater oil and gas activity also has been significantly increasing. At the end of 1999, deepwater oil production increased 41 percent over 1998 levels. A milestone was reached in late 1999 when oil production from the deep water exceeded that from the shallow water for the first time. Further, nine deepwater projects began production in 1999 and several more plan to be in production by the year 2004.

Table 3-12

Deepwater Production as a Percentage of Total Production: 1985 - 1999

Year	Percent of Total GOM Production		Percentage Increase	
	Oil	Gas	Oil	Gas
1985	6.0	0.8	-	-
1986	5.3	0.9	-9.3	9
1987	5.2	1.0	-10	19.9
1988	4.3	0.8	-23	-13
1989	3.6	0.7	-22	-16
1990	4.4	0.6	21.3	-4.3
1991	7.7	1.2	88.4	91.5
1992	12.2	1.9	62.9	49.3
1993	11.9	2.5	-1.4	37.4
1994	13.2	3.3	13.6	33
1995	16.0	3.8	32	13.5
1996	19.5	5.4	30.8	53.7
1997	26.3	7.4	50.2	37.2
1998	35.8	11.1	46.7	46.8
1999	45.4	16.8	41.3	50.8

Source: MMS, 2000c.

After a late beginning, subsea completions now account for a substantial portion of deepwater production. Subsea gas production began in 1993 while subsea oil production began in 1995. After six to four years, subsea completions account for 40 percent of the deepwater gas production and 25 percent of the deepwater oil production.

One of the reasons for the success of deepwater operations is high well production rates. Milestones include Bullwinkle in 1992 (5,000 BOPD), Auger in 1994 (10,000 BOPD), and Ursa in 1999 (36,520 BOPD). These are single-well production rates, not lease production rates. Many deepwater fields produce at rates higher than ever seen before in the Gulf. For comparison, the Offshore EIA modeled a typical shallow-water well with a peak production rate of 500 BOPD. What this means is that large, deepwater operations will rapidly dominate Gulf production. Deepwater drilling occurs in the area of highest interest for using synthetic drilling fluids. The cost or savings incurred under the rule are so small compared to the total cost of drilling an offshore well that the effluent guidelines are likely to play little part in whether to drill but will be a factor in which fluid to use.

3.4 REFERENCES

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SECTION FOUR

REGULATORY OPTIONS AND AGGREGATE COSTS OF THE EFFLUENT GUIDELINES

This section presents the regulatory options considered for offshore drilling operations and the total costs of compliance for the SBF Guidelines (see the Development Document for more details). Only wells that are drilled with SBFs or those drilled with OBFs or WBFs that are assumed to convert to SBFs are determined to have costs or realize savings under the regulation. These analyses focus on drill **cuttings**; zero discharge of SBF not associated with cuttings is current practice and thus operators incur no cost to meet the zero discharge requirement in the final rule.

4.1 REGULATORY OPTIONS

In the February 1999 Proposal, EPA discussed two primary options for SBFs associated with drill cuttings, "SBF-cuttings":

- a controlled discharge option (based on two SBF-cuttings discharges from solids control equipment), and
- a zero discharge option.

In the April 2000 NODA (65 FR 21560), EPA revised and added one new controlled discharge option for SBF-cuttings.

Hence, EPA considered three primary options for the final rule for Best Available Treatment Economically Achievable (BAT) for existing sources and New Source Performance Standards (NSPS) for new sources [1] :

[1]Best Practical Control Technology (BPT) and Best Conventional Pollutant control Technology (BCT) are associated with no incremental costs so are not discussed in this report. Additionally, there are no known indirect dischargers so Pretreatment Standards for Existing Sources (PSES) and Pretreatment Standards for New Sources (PSNS) also are not discussed.

controlled discharge of cuttings wetted with SBF, called "BAT 1" although it applies to both BAT and NSPS discharges

controlled discharge of cuttings wetted with SBF, called "BAT 2," although it applies to both BAT and NSPS discharges and

zero discharge, called "zero discharge."

There is also an implicit no-action option.

Both BAT and NSPS discharge options (BAT 1 and BAT 2) control the characteristics the stock base fluid through limitations on:

PAH content

sediment toxicity

biodegradation rate, and

the current requirements of stock limitations on barite of mercury and cadmium.

Both discharge options control the characteristics and volumes of cuttings discharged through limitations on:

formation oil content

maximum aqueous toxicity of discharged drilling waste

the quantity of SBF base fluid reaching the water at the point of discharge.

Both discharge options retain the current prohibition on diesel oil discharge and control sheen formation at the point of discharge under BPT and BCT limitations. EPA believes that all of these components are essential for appropriate control of SBF-cuttings discharges.

When the used drilling fluid returns up the borehole, it passes through three to four cleaning phases to remove the cuttings and recycle the drilling fluid. The first two phases are "shale shakers;" primary and secondary shale shakers differ according to the coarseness of the mesh through which the fluid passes. The third phase is a “mud cleaner;” a high speed shale shaker or a centrifuge. The fourth phase is a “cuttings dryer or squeeze press” to further reduce the amount of SBF adhering to the cuttings. The third and fourth phases remove fine particles (“fines”) from the drilling fluid. The BAT 1 engineering model assumes that both the cuttings (phases 1 and 2) and fines (phases 3 and 4) are discharged, i.e., the discharge limits should allow this practice. BAT 2 option differs from the BAT 1 option in that to meet discharge limits, it is likely that only the cuttings would be discharged while the fines will be retained for zero discharge via hauling to shore for land-based disposal. Hence, this option has a higher control requirement and, thus, most likely requires operators to dispose of fines on land.

The zero discharge option has the potential to generate additional costs, but only for wells in the Gulf of Mexico because the Alaska and California wells are at zero discharge in the baseline. The SBF wells in the Gulf of Mexico are discharging, but at a long-term average of 10.2 % retention of base fluid on cuttings in the baseline, while OBF-drilled wells are at zero discharge. Thus under the zero discharge option, only wells drilled with SBFs in the Gulf are affected. The zero discharge option is associated with costs to haul cuttings to shore with land treatment/disposal or to inject the wastes at or near the site of the drilling operation. EPA’s selected option for the final rule, for both BAT and NSPS, is BAT Option 2.

4.2 TOTAL COMPLIANCE COSTS

As Table 4-1 shows, total compliance costs for the discharge options are actually cost savings due to the value of the drilling fluids captured for recycling. For BAT, the aggregate annual cost **savings** are $46.6 million and $46.5 million for discharge options 1 and 2, respectively. (BAT 2, the selected option, has lower savings because of the need to haul the fines to shore for land disposal). For NSPS, the annual cost savings is $2.5 million for discharge options 1 and 2.

In contrast, industry incurs costs under the zero discharge option. These costs are estimated to be $28.7 million per year under BAT and $0.4 million per year under NSPS for a total of $29.1 million per year.

Table 4-1

Incremental Costs/Cost Savings of Compliance with the SBF Guidelines

(Thousands, 1999 Dollars)

Option	**BAT**				**NSPS**				**Total Costs/Cost Savings**
	Gulf	**CA**	**AK**	**Total**	**Gulf**	**CA**	**AK**	**Total**	
Discharge Option 1	(46,742)	0	100	(46,642)	(2,484)	0	0	(2,484)	(49,126)
Discharge Option 2	(46,562)	0	100	(46,462)	(2,480)	0	0	(2,480)	(48,942)
Zero Discharge	28,732	0	0	28,732	376	0	0	376	29,108

Note: Cost savings result from:
(1) 1/3 fewer SBF wells/footage required to develop a reservoir than WBF,
(2) reduction in rig costs due to 50% decreased time to total depth using SBF versus WBF,
(3) savings in the cost of discharged WBF, and
(4) the smaller volumes of waste that need disposal with a synthetic-based fluid.
Current practice is zero discharge for Alaska.

SECTION FIVE

ECONOMIC IMPACTS OF THE PROPOSED RULEMAKING

EPA selected the BAT 2 discharge option for promulgation. Under this decision, the Final SBF Guidelines will provide a cost savings to industry. This cost savings will be experienced directly by wells currently (i.e., in the baseline) discharging cuttings contaminated with SBFs and other water non-dispersible fluids, by wells currently land-disposing or injecting OBF cuttings in the baseline that convert to SBF, and by WBF wells that convert to SBF due to greater drilling efficiencies (see Development Document for details). Operations that continue to use WBFs would not be directly affected by the SBF Guidelines. As discussed in Section Four, the cost savings for SBF dischargers result from the use of improved solids control equipment and the subsequent ability of operators to recycle additional volumes of expensive SBFs, which generally offsets the costs of the improved solids control equipment. For wells that would have been drilled with OBF, the cost savings result from switching to SBF and discharging, thus avoiding higher zero discharge disposal costs.

For each regulatory option, EPA estimated the change in the cost of drilling wells, impacts on operating a deepwater production unit (typically a platform), employment impacts in the oil and gas industry, and impacts on related industries (e.g., drilling contractors, drilling fluid companies, mud cleaning equipment rental firms, transport and disposal firms, etc.) as a result of the selected BAT and NSPS requirements. EPA looked at deepwater projects to respond to a comment that such projects were much different form those investigated during EPA's offshore rulemaking. The results of the deepwater analyses are summarized below in Section 5.1 (for existing sources) and Section 5.2 (for new sources). Impacts on small firms are discussed in Section Six.

5.1 IMPACTS ON EXISTING SOURCES

5.1.1 Impacts on Costs of Drilling Wells

As discussed in Section Four, under the discharge option, EPA projects aggregate costs savings for wells using SBFs, wells using OBFs that convert to SBFs, and wells using WBFs that convert to SBFs. Table 5-1 provides estimates of potential costs or cost savings as a percentage of total costs to drill a well associated with various subsets of these well types (including WBF wells).[1] Costs and cost savings vary depending on the region, the type of fluid currently used, and the operator's choice of zero discharge (under the zero discharge option only)–hauling to shore for disposal or injecting the waste. (The latter, less expensive option is not technically feasible at all locations). See the SBF Development Document for detailed information on how the numbers of wells were estimated in each category and Appendix A of this report for how the aggregate costs of each well type were disaggregated to estimate a per-well cost.

Under the selected option (BAT 2), all but one category of wells in the Gulf of Mexico show a cost **savings** (Table 5-1). This results from a combination of factors—SBFs produce smaller volumes of drilling waste than WBFs do, the increased cuttings treatment recovers more of the expensive SBF, or the operator no longer needs to transport oil-based cuttings to shore for disposal. These savings range from negligible to 25 percent of the cost of drilling an exploratory well in shallow water. In the aggregate, then, industry realizes a cost **savings** under the selected option. The one well in Alaska (Cook Inlet) potentially affected by the rule shows a cost of 3.6 percent of drilling costs.[2]

Only shallow water SBF wells show a cost **increase** because the additional recovery of SBF is not sufficient to offset the cost of the equipment; shallow wells use less drilling fluid than deeper wells. The increase, however, is three-tenths of one percent. A certain percentage of wells might incur a higher

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[1]Table 5-1 shows per-well BAT costs which include retrofit costs for installation and downtime. NSPS costs do not need retrofit costs and per-well NSPS costs are lower. To be conservative, EPA examined the economic impacts on BAT and NSPS projects with per-well BAT costs.

[2]This cost would not actually be incurred since OBF drilling could continue at no additional cost.

Table 5-1

Cost Savings of the BAT Discharge Option as a Percentage of Baseline Costs

Type of Well	Number of Wells Affected by the Rule	Incremental Cost of Option 1 (per well)	Incremental Cost of Option 2 (per well)	Incremental Cost of Option 3 (Zero Discharge) (per well)	Total Baseline Cost of Drilling Well ($MM)	Costs as a Percentage of Total Drilling Costs		
						BAT Option 1	BAT Option 2	Zero D. Option 3
GULF OF MEXICO								
Development Wells								
SBF - Deep	16	($2,785)	($2,404)	$299,776	$20.0	0.0%	0.0%	1.5%
SBF - Shallow	86	$7,514	$7,260	$27,216	$2.9	0.3%	0.3%	0.9%
OBF - Shallow	17	($20,597)	($20,845)	$0	$2.9	-0.7%	-0.7%	0.0%
WBF - Deep	1	($820,278)	($819,897)	$0	$20.0	-4.1%	-4.1%	0.0%
WBF - Shallow	21	($523,914)	($524,162)	$0	$2.9	-18.1%	-18.1%	0.0%
Exploratory Wells								
SBF - Deep	48	($30,626)	($28,007)	$688,473	$25.0	-0.1%	-0.1%	2.8%
SBF - Shallow	51	($4,510)	($3,481)	$61,460	$4.9	-0.1%	-0.1%	1.3%
OBF - Shallow	10	($65,728)	($64,699)	$0	$4.9	-1.3%	-1.3%	0.0%
WBF - Deep	1	($1,822,587)	($1,819,968)	$0	$30.0	-6.1%	-6.1%	0.0%
WBF - Shallow	13	($1,120,327)	($1,199,298)	$0	$4.9	-22.9%	-24.5%	0.0%
ALASKA								
Shallow Water OBF Development	1	$99,968	$99,968	$0	$2.8	3.6%	3.6%	0.0%

Notes: Negative values or values in parentheses represent cost savings.
Number of wells includes all SBF wells (201) and OBF and WBF wells that would change to SBF (81). Because of the improved directional drilling capabilities of SBF, fewer SBF wells are needed to replace WBF wells. A 2:3 replacement ratio means the 36 SBF wells replace 54 WBF wells. See SBF Development Document for details.

cost for SBFs that meet the stock limitations over SBFs that do not. EPA also examined this type of increase by modeling a cost increase from $160/bbl for the SBF and a primary shale shaker to $300/bbl for the SBF and a cuttings dryer[3]. For shallow water wells, the incremental cost was $48,000 for a development well (compared to a $2.9 million total baseline drilling cost) and $61,000 for an exploratory well (compared to a $4.9 million total baseline drilling cost).

In other words, the extremely conservative assumptions lead to no more than a 1.7 percent increase in the total drilling cost. It is unlikely that such a small increase in total drilling cost would affect the decision whether or not to drill. It would only make sense not to drill a well if the difference in estimated net present values of a project with and without that well is less than the incremental cost of the more expensive fluid for that well. This might happen when wells are drilled into marginal fields. To examine the highest number of operations that might be affected by increased drilling fluid costs, EPA examined the number of wells per year that have been drilled recently using SBFs in shallow water operations, i.e, where SBF formulations might have to be changed to meet the BAT requirements (see Development Document). EPA identified about 40 wells in this category, about 3 percent of all wells drilled annually in the Gulf of Mexico. Thus, no more than 3 percent of Gulf wells would not be drilled. Because it is likely that any wells not drilled would be in marginal fields, lost production would most likely be far less than 3 percent of Gulf production. There is the social cost of the lost production as well (which does not affect the operator), but that should be small relative to the total recoverable production in the Gulf, since it would affect a relatively small number of wells and these are wells drilled into marginal fields.

Under rejected BAT 1 option, the results look very similar to those for BAT 2. The only difference is for shallow exploratory WBF wells where the BAT 1 savings is about 1.5 percent less than the savings for BAT 2.

Under the rejected zero discharge option, the results fall into two categories—wells without incremental costs and wells with incremental costs. Wells drilled with oil-based fluids in the baseline would have had to meet zero discharge under current requirements; hence, they incur no incremental costs. Wells drilled with water-based fluids would not change to SBF; hence, they incur no incremental costs. Wells drilled with SBF fluids incur the additional costs of zero discharge. These added costs range from about 1 to 3 percent of average drilling costs in the Gulf. Given the basic cost of drilling an offshore or coastal

[3]The cost analysis uses a weighted average of SBF fluid costs (over $200/bbl).

(Alaska) well, the incremental costs of the rule are highly unlikely to change an operator's decision whether to drill a well. Once the operator has decided to drill a well, the regulation will be one of the factors in the operator's decision of which fluid to use.

5.1.2 Impacts on Platforms and Production

As discussed in the NODA, EPA has developed model projects based closely on a number of existing projects currently operating in deepwater Gulf locations.[4] Appendix B and the *Summary of Data To Be Used in Economic Modeling* (Section III.G of the Rulemaking Record) contain details on the methodology, data, and assumptions on which the models are based and how the models were constructed. EPA received no comments on the methodology and data presented in the NODA. The only additional data input not presented in the *Summary of Data To Be Used in Economic Modeling* is assumed drilling activity. Drilling activity is estimated for existing and new projects based on the drilling required to approximate original proved reserves in new projects without exceeding remaining proved reserves by a wide margin at existing projects (See Appendix B).

These models are based on a cash flow approach. The projected revenues are compared to operating costs at each year for each model project. Revenues are based on an assumed price of oil, current and projected production of oil and gas, well production decline rates, and royalty rates. Operating costs are based on an assumed cost per BOE produced. The model runs for 30 years or is assumed to shut in when operating costs exceed revenues. That is, the economic models have differing lifetimes according to project characteristics and each model may have a shortened lifetime as a result of incremental pollution control costs. The model then calculates the lifetime of the project, total production, and the net present value of the operation (net income of the operation over the life of the project in terms of today's dollars), which includes the net operating earnings, taxes, expenditures on drilling, other capital expenditures, etc. A positive net present value means that the project is a good investment. In this case, the return is greater than the discount rate, which represents the opportunity cost of capital. If the net present value is negative, it means that money would have been better invested elsewhere. For existing projects, the model uses current operations; all expenditures in prior years, such as exploration, delineation, and infrastructure development

[4]EPA presented findings for Alaska, California, and shallow Gulf of Mexico projects at proposal based on findings in the Offshore rulemaking. Because current requirements for Alaska are zero discharge, it would not make financial sense for a project to switch to SBF and incur the additional costs shown in Table 5-1. EPA, therefore, did not re-analyze the Alaska model for promulgation.

costs are considered sunk costs and are not addressed. For new projects, the model uses data and assumptions about timing of the various phases of exploration, delineation and development, along with cost assumptions about costs incurred during these phases to compute a full lifetime financial model of these projects.

Each model is run twice—with and without the change due to pollution control. The models support changes in both directions, i.e., costs or savings. This means that only the incremental cost (or cost savings) of drilling under the three regulatory options is changed and then the postcompliance results are compared to those calculated under baseline assumptions. If a model shows the net present value of a project to be positive in the baseline, but would have a negative net present value under any of the options, some or all of the wells would not be drilled. This difference between baseline and postcompliance would generate production impacts.

The same approach is used for modeling both existing and new projects. Since the NODA, two projects used for modeling have shut in (Diamond and Cooper) and EPA has removed them from the analysis (a total of 18 projects remain for modeling existing projects and 13 remain for modeling new projects). See *Summary of Data To Be Used in Economic Modeling*, Section III.G. of the NODA record for additional information on the projects used for modeling impacts and the assumptions used to construct each model new source project.

The results of the analysis of existing deepwater Gulf projects shows that the rule, regardless of option chosen, does not affect the volumes of production or the lifetime of projects. Under all options, the net present value of each of the existing projects is still positive postcompliance under all options investigated. The rule, however, has an impact on the net present value of the projects (see Table 5-2 through 5-5), but the impact on net present value is nearly negligible for all size projects. Thus the rule will have a very small impact on the rate of return for an existing project, but will not change the fact that continuing to invest in the project is a good investment (the net present value is still greater than $0 postcompliance). It also minimally affects the amount of federal taxes paid due to the tax shield on capital and operating costs.

Table 5-2

Impact of BAT Options on Small Deepwater GOM Projects (1999$)

Type of Impact	Baseline Current	Option BAT 1	Option BAT 2	Zero Discharge
Projected lifetime discounted production (PVBOE)	19,874,315	19,874,315	19,874,315	19,874,315
Change in discounted production (PVBOE)	--	0	0	0
Percentage change in discounted baseline production	--	0.0%	0.0%	0.0%
Total projected lifetime production (BOE)	31,702,089	31,702,089	31,702,089	31,702,089
Change in total projected lifetime production (BOE)	--	0	0	0
Percentage change in discounted baseline production	--	0.0%	0.0%	0.0%
Present value of project net worth (NPV) ($000)	$73,453	$73,457	$73,456	$73,030
Change in NPV ($000)	--	$4	$3	($423)
Percentage change in NPV	--	0.0%	0.0%	-0.6%
Number of platforms ceasing production in first year (postcompliance)	0	0	0	0
Total number of production years	49	49	49	49
Average production years per platform (all platforms)	12.3	12.3	12.3	12.3
Average production years per platform (nonclosing platforms)	12.3	12.3	12.3	12.3
Total production years lost among closing platforms	--	0	0	0
Total production years lost among nonclosing platforms	--	0	0	0
Present value of federal income taxes collected ($000)	$37,894	$37,896	$37,896	$37,708
Change in present value of federal income taxes ($000)	--	$2	$1	($186)
Percentage change in federal income taxes	--	0.0%	0.0%	-0.5%
Present value of royalties collected ($000)	$37,217	$37,217	$37,217	$37,217
Change in present value of royalties ($000)	--	$0	$0	$0
Percentage change in royalties	--	0.0%	0.0%	0.0%

Source: EPA, 2000. Deepwater Production Loss Model.

Table 5-3

Impact of BAT Options on Medium Deepwater GOM Projects (1999$)

Type of Impact	Baseline Current	Option BAT 1	Option BAT 2	Zero Discharge
Projected lifetime discounted production (PVBOE)	253,419,304	253,419,304	253,419,304	253,419,304
Change in discounted production (PVBOE)	--	0	0	0
Percentage change in discounted baseline production	--	0.0%	0.0%	0.0%
Total projected lifetime production (BOE)	362,731,566	362,731,566	362,731,566	362,731,566
Change in total projected lifetime production (BOE)	--	0	0	0
Percentage change in discounted baseline production	--	0.0%	0.0%	0.0%
Present value of project net worth (NPV) ($000)	$989,997	$990,044	$990,037	$984,989
Change in NPV ($000)	--	$47	$40	($5,008)
Percentage change in NPV	--	0.0%	0.0%	-0.5%
Number of platforms ceasing production in first year (postcompliance)	0	0	0	0
Total number of production years	89	89	89	89
Average production years per platform (all platforms)	11.1	11.1	11.1	11.1
Average production years per platform (nonclosing platforms)	11.1	11.1	11.1	11.1
Total production years lost among closing platforms	--	0	0	0
Total production years lost among nonclosing platforms	--	0	0	0
Present value of federal income taxes collected ($000)	$526,735	$526,756	$526,753	$524,424
Change in present value of federal income taxes ($000)	--	$21	$19	($2,311)
Percentage change in federal income taxes	--	0.0%	0.0%	-0.4%
Present value of royalties collected ($000)	$446,024	$446,024	$446,024	$446,024
Change in present value of royalties ($000)	--	$0	$0	$0
Percentage change in royalties	--	0.0%	0.0%	0.0%

Source: EPA, 2000. Deepwater Production Loss Model.

Table 5-4

Impact of BAT Options on Large Deepwater GOM Projects (1999$)

Type of Impact	Baseline Current	Option BAT 1	Option BAT 2	Zero Discharge
Projected lifetime discounted production (PVBOE)	1,127,389,726	1,127,389,726	1,127,389,726	1,127,389,726
Change in discounted production (PVBOE)	--	0	0	0
Percentage change in discounted baseline production	--	0.0%	0.0%	0.0%
Total projected lifetime production (BOE)	1,651,984,245	1,651,984,245	1,651,984,245	1,651,984,245
Change in total projected lifetime production (BOE)	--	0	0	0
Percentage change in discounted baseline production	--	0.0%	0.0%	0.0%
Present value of project net worth (NPV) ($000)	$5,552,828	$5,553,014	$5,552,989	$5,532,852
Change in NPV ($000)	--	$186	$160	($19,976)
Percentage change in NPV	--	0.0%	0.0%	-0.4%
Number of platforms ceasing production in first year (postcompliance)	0	0	0	0
Total number of production years	120	120	120	120
Average production years per platform (all platforms)	15	15	15	15
Average production years per platform (nonclosing platforms)	15	15	15	15
Total production years lost among closing platforms	--	0	0	0
Total production years lost among nonclosing platforms	--	0	0	0
Present value of federal income taxes collected ($000)	$2,959,419	$2,959,502	$2,959,491	$2,950,429
Change in present value of federal income taxes ($000)	--	$84	$72	($8,990)
Percentage change in federal income taxes	--	0.0%	0.0%	-0.3%
Present value of royalties collected ($000)	$1,900,407	$1,900,407	$1,900,407	$1,900,407
Change in present value of royalties ($000)	--	$0	$0	$0
Percentage change in royalties	--	0.0%	0.0%	0.0%

Source: EPA, 2000. Deepwater Production Loss Model.

Table 5-5

Impact of BAT Options on All Deepwater GOM Projects (1999$)

Type of Impact	Baseline Current	Option BAT 1	Option BAT 2	Zero Discharge
Projected lifetime discounted production (PVBOE)	1,400,683,345	1,400,683,345	1,400,683,345	1,400,683,345
Change in discounted production (PVBOE)	–	0	0	0
Percentage change in discounted baseline production	--	0.0%	0.0%	0.0%
Total projected lifetime production (BOE)	2,046,417,900	2,046,417,900	2,046,417,900	2,046,417,900
Change in total projected lifetime production (BOE)	–	0	0	0
Percentage change in discounted baseline production	--	0.0%	0.0%	0.0%
Present value of project net worth (NPV) ($000)	$6,616,278	$6,616,514	$6,616,482	$6,590,871
Change in NPV ($000)	--	$236	$204	($28,408)
Percentage change in NPV	--	0.0%	0.0%	-0.4%
Number of platforms ceasing production in first year (postcompliance)	0	0	0	0
Total number of production years	258	258	258	258
Average production years per platform (all platforms)	13	13	13	13
Average production years per platform (nonclosing platforms)	13	13	13	13
Total production years lost among closing platforms	--	0	0	0
Total production years lost among nonclosing platforms	--	0	0	0
Present value of federal income taxes collected ($000)	$3,524,048	$3,524,155	$3,524,140	$3,512,560
Change in present value of federal income taxes ($000)	--	$107	$92	($11,488)
Percentage change in federal income taxes	--	0.0%	0.0%	-0.3%
Present value of royalties collected ($000)	$2,383,648	$2,383,648	$2,383,648	$2,383,648
Change in present value of royalties ($000)	--	$0	$0	$0
Percentage change in royalties	--	0.0%	0.0%	0.0%

Source: EPA, 2000. Deepwater Production Loss Model.

Under the selected option (BAT 2), NPV increases negligibly (less than 0.1 percent) for all BAT projects. The present value of Federal income taxes paid increases negligibly (less than 0.1 percent), as well. EPA concludes that the selected option is economically achievable, since it results in a minor cost savings.

Under the rejected BAT 1 option, the results are very similar to those for the selected option, a negligible increase in NPV and Federal taxes paid. Under the rejected zero discharge option, small and medium size projects show a decline of at most 0.6 percent in NPV over the life of the project. Large projects show a 0.4 percent decline in NPV.

5.1.3 Impacts on Firms

Other than in Section 6, which discusses impacts on small businesses, EPA does not discuss impacts on firms. Industry comments indicated that identifying impacts at the firm level are irrelevant and that impacts of the rule should be determined at the oil and gas project level. EPA has estimated project level impacts in Section 5.1.2 and Section 5.2 , and thus has not updated a firm level analysis, except as the rule affects small business entities (See Section 6).

5.1.4 Secondary Impacts

5.1.4.1 Impacts on Employment and Output

EPA anticipates no negative impacts on employment and output (revenues) from the selected discharge option because, in the aggregate, it results in cost savings. Changes in employment and output are directly proportional to costs of compliance, that is, higher costs lead to lower employment and output. Likewise, a cost savings would minimally increase employment and output in the oil and gas industry, but these gains would be offset by loses elsewhere in the economy (e.g., waste disposal firms). To the extent that any costs savings might be reinvested in additional drilling or otherwise encourage additional drilling, employment and output could increase in the oil and gas industry by more than that associated with the costs savings alone. EPA has not quantified this potentially positive, albeit small, effect. Under the zero discharge option, the industry incurs costs and not savings, thereby leading to small output losses and employment losses in the oil and gas industry. These losses, however, would be offset by gains elsewhere in the economy (e.g., waste disposal firms). The net effect of the rule on the U.S. economy under either option is likely to be close to zero.

To determine impacts on employment and output, EPA uses input-output multipliers developed by the Bureau of Economic Analysis (BEA, 1996). Input-output multipliers allow EPA to calculate the total number of jobs gained or lost throughout the U.S. economy in all industries associated with a change of $1 million of output in a specific industry and the total amount of output gained or lost throughout the U.S. economy based on the change in output in the specific industry. Compliance costs or savings resulting from the SBF Guidelines can be considered equivalent to the change in output for the oil and gas industry.[5]

The BEA national level employment multiplier relevant to the oil and gas industry is 13.0, which means for every $1 million output gain or loss, 13 jobs in the U.S. economy will be gained or lost.

Additional output losses (those additional to output losses in the oil and gas industry) can also be calculated for a full accounting of economic losses because the losses in the oil and gas industry can lead to additional losses in related industries, such as those providing services to the oil and gas industry. BEA's final demand output multiplier allows the calculation of the total output loss to the U.S. economy as a whole based on each million dollar change in output in a particular industry. The relevant BEA output multiplier for the oil and gas industry is 1.9420, which means for every $1 million of output loss an additional $942,000 million is lost throughout the U.S. economy.

Table 5-6 presents the results of the analysis of employment and output effects stemming from all three options considered. As the table shows, the selected discharge option 2 is estimated to result in employment gains of 636 full-time equivalents (1 FTE=2,080 hours and can be equated with one full-time job) and gains of $95 million per year in output for the U.S. economy as a whole. The zero discharge option is estimated to result in a loss of 378 FTEs and a loss of $56.5 million per year in output for the U.S. economy as a whole (losses within the oil and gas industry would be less).

[5]For more information on input-output analysis in the oil and gas industry, see EPA, 1996.

Table 5-6

Employment and Output Effects Associated With SBF Guidelines Options ($1999)

Option	Cost Savings (+) or Compliance Cost (-) ($ Millions)	Gains (+) or Loss (-) in Employment*	Total Gains (+) or Loss (-) in Output** ($ Millions)
Discharge Option 1	$49.1	+639 FTEs	+$95.4
Discharge Option 2	$48.9	+636 FTEs	+$95
Option 3 (Zero Discharge)	-$29.1	-378FTEs	-$56.5

Source: Section Four and BEA, 1996.
* Based on 13 jobs gained or lost per $1 million change in output on the affected industry.
** Based on $942,000 additional output changes in other industries in the U.S. for each $1 million change in output for the oil and gas industry.

Note, however, these are not net losses and gains. Other industries, such as the waste disposal industry will lose output and employment under the discharge option and will gain output and employment under the zero discharge option. When these changes are subtracted from changes identified above, both gains and losses will be reduced. The net impact on output and employment would be close to zero under all options. Even these gross changes in employment and output, however, are very small relative to total U.S. employment (133 million persons) and gross domestic product ($8.8 trillion) in 1999 (CEA, 2000).

5.1.4.2 Secondary Impacts on Associated Industries

EPA qualitatively analyzed the secondary impacts on associated industries from the selected option. Impacts on drilling contractors should be neutral to positive, with some increase in employment in these firms occurring if they reinvest the cost savings. Impacts on firms supplying drilling fluids should be neutral to positive, since most firms supplying drilling fluids stock both OBFs and SBFs and most producers make more than one product. To the extent that SBFs have, at a minimum, the same profit margin as OBFs, there would be little to no impacts on these firms, because SBFs would replace OBFs in some instances under the selected discharge option. If drilling increases as a result of reinvestment, some positive impacts might occur.

Firms that provide rental of solids separation systems presumably would purchase and provide improved solids separation systems once demand for these systems developed with the promulgation of the rule. Because these more efficient systems would most likely be rented in addition to, rather than in place of, less efficient systems, impacts on these firms would be positive.

Firms that manufacture the improved solids separation equipment and firms that manufacture equipment or provide services needed to comply with the new testing requirements will prosper.

The firms providing transport and landfilling or injection of OBF-contaminated cuttings would sustain economic losses as a result of the rule. Under the selected option, EPA estimates that waste generated for disposal by landfill and injection would be reduced by several million pounds per year. Under a zero discharge option, these firms would experience potential economic gains, because more waste would be generated for land disposal or injection than is currently generated.

5.1.4.3 Other Secondary Impacts

There will be no measurable impacts on the balance of trade or inflation as the result of this final rule. EPA projects insignificant impacts on domestic drilling and production and, therefore insignificant impacts on the U.S. demand for imported oil. Additionally, even if there were costs associated with this rule, the industry has no ability to pass on costs to consumers as price takers in the world oil market and thus this rule would have no impact on inflation (see EPA, 1993 and 1996).

5.2 IMPACTS ON NEW SOURCES

The final NSPS option is the same discharge option selected for BAT. Under the definitions of new source in the Offshore Oil and Gas Effluent Guidelines, an oil and gas operation is considered a new source only when significant site preparation work and other criteria are met (see 40 CFR 435.11). Individual exploratory wells, wells drilled from existing platforms and wells drilled and connected to an existing separation/treatment facility without substantial construction of additional infrastructure are not new sources.

Industry provided assumptions on capital and operating costs for deepwater new sources (ERG, 2000). As a result of incorporating industry's recommended oil price of $15/bbl, most deepwater Gulf NSPS projects show negative net present values (NPVs) before the regulation. EPA conducted a sensitivity analysis using $20/bbl for oil and the NPVs for most large projects are positive although NPVs for small and medium projects remain negative. Industry might still operate projects that show a negative NPV in the baseline. One, industry might desire to expand infrastructure in the deepwater Gulf; these early deepwater projects on which the NSPS analysis is modeled may actually be an investment in the future of deepwater Gulf development. Second, a project may be undertaken, and only after it is developed is it known that it is not providing a return on the initial investment. Despite this, once built, assuming the project has positive earnings, the continued operation defrays the cost of the infrastructure, and the operator continues to produce as long as earnings are positive. Model projects that are estimated to have negative net present value in the baseline are assumed to operate anyway as long as they have positive earnings, since any earnings will defray the costs of the infrastructure. These operations will continue to drill as long as NPV under a drilling scenario is a smaller loss than the NPV under a no-drilling scenario. The impact of the options on these projects is measured in terms of how much the options might change net present value in absolute terms. Impacts on those projects with positive net present value in the baseline are judged either as declines in net present value or, if the net present value becomes negative postcompliance, as impacts on production, due to the fact that a project would not be undertaken if net present value is negative postcompliance.

Table 5-7 through 5-10 show the results of the NSPS analysis. Under the selected option (BAT 2), NPV increases negligibly (0.1 percent or less) for all NSPS projects. The present value of Federal income taxes paid increases negligibly (about 0.1 percent), as well. EPA concludes that the selected option is economically achievable, since it results in a minor cost savings.

Table 5-7

Impact of NSPS Options on Small Deepwater GOM Platforms (1999$)

Type of Impact	Baseline Current	Option BAT 1	Option BAT 2	Zero Discharge
Projected lifetime discounted production (PVBOE)	13,605,848	13,605,848	13,605,848	13,605,848
Change in discounted production (PVBOE)	--	0	0	0
Percentage change in discounted baseline production	--	0.0%	0.0%	0.0%
Total projected lifetime production (BOE)	31,702,089	31,702,089	31,702,089	31,702,089
Change in total projected lifetime production (BOE)	--	0	0	0
Percentage change in discounted baseline production	--	0.0%	0.0%	0.0%
Present value of project net worth (NPV) ($000)	($137,367)	($137,251)	($137,262)	($140,852)
Change in NPV ($000)	--	$115	$105	($3,486)
Percentage change in NPV	--	0.0%	0.0%	-2.5%
Number of platforms ceasing production in first year (postcompliance)	0	0	0	0
Total number of production years	79	79	79	79
Average production years per platform (all platforms)	19.8	19.8	19.8	19.8
Average production years per platform (nonclosing platforms)	19.8	19.8	19.8	19.8
Total production years lost among closing platforms	--	0	0	0
Total production years lost among nonclosing platforms	--	0	0	0
Present value of federal income taxes collected ($000)	($10,521)	($10,505)	($10,507)	($11,120)
Change in present value of federal income taxes ($000)	--	$16	$15	($599)
Percentage change in federal income taxes	--	0.2%	0.1%	-5.7%
Present value of royalties collected ($000)	$25,891	$25,891	$25,891	$25,891
Change in present value of royalties ($000)	--	$0	$0	$0
Percentage change in royalties	--	0.0%	0.0%	0.0%

Source: EPA, 2000. Deepwater Production Loss Model.

Table 5-8

Impact of NSPS Options on Medium Deepwater GOM Platforms (1999$)

Type of Impact	Baseline Current	Option BAT 1	Option BAT 2	Zero Discharge
Projected lifetime discounted production (PVBOE)	114,524,539	114,524,539	114,524,539	114,524,539
Change in discounted production (PVBOE)	--	0	0	0
Percentage change in discounted baseline production	--	0.0%	0.0%	0.0%
Total projected lifetime production (BOE)	366,997,146	366,997,146	366,997,146	366,997,146
Change in total projected lifetime production (BOE)	--	0	0	0
Percentage change in discounted baseline production	--	0.0%	0.0%	0.0%
Present value of project net worth (NPV) ($000)	($1,207,300)	($1,206,638)	($1,206,701)	($1,233,002)
Change in NPV ($000)	--	$662	$599	($25,702)
Percentage change in NPV	--	0.1%	0.0%	-2.1%
Number of platforms ceasing production in first year (postcompliance)	0	0	0	0
Total number of production years	109	109	109	109
Average production years per platform (all platforms)	18.2	18.2	18.2	18.2
Average production years per platform (nonclosing platforms)	18.2	18.2	18.2	18.2
Total production years lost among closing platforms	--	0	0	0
Total production years lost among nonclosing platforms	--	0	0	0
Present value of federal income taxes collected ($000)	$207,797	$207,825	$207,822	$205,506
Change in present value of federal income taxes ($000)	--	$28	$25	($2,291)
Percentage change in federal income taxes	--	0.0%	0.0%	-1.1%
Present value of royalties collected ($000)	$215,098	$215,098	$215,098	$215,098
Change in present value of royalties ($000)	--	$0	$0	$0
Percentage change in royalties	--	0.0%	0.0%	0.0%

Source: EPA, 2000. Deepwater Production Loss Model.

Table 5-9

Impact of NSPS Options on Large Deepwater GOM Platforms (1999$)

Type of Impact	Baseline Current	Option BAT 1	Option BAT 2	Zero Discharge
Projected lifetime discounted production (PVBOE)	480,787,323	480,787,323	480,787,323	480,787,323
Change in discounted production (PVBOE)	--	0	0	0
Percentage change in discounted baseline production	--	0.0%	0.0%	0.0%
Total projected lifetime production (BOE)	1,418,373,281	1,418,373,281	1,418,373,281	1,418,373,281
Change in total projected lifetime production (BOE)	--	0	0	0
Percentage change in discounted baseline production	--	0.0%	0.0%	0.0%
Present value of project net worth (NPV) ($000)	($697,434)	($696,900)	($696,956)	($727,094)
Change in NPV ($000)	--	$535	$478	($29,659)
Percentage change in NPV	--	0.1%	0.1%	-4.3%
Number of platforms ceasing production in first year (postcompliance)	0	0	0	0
Total number of production years	77	77	77	77
Average production years per platform (all platforms)	15	15	15	15
Average production years per platform (nonclosing platforms)	15	15	15	15
Total production years lost among closing platforms	--	0	0	0
Total production years lost among nonclosing platforms	--	0	0	0
Present value of federal income taxes collected ($000)	$1,183,530	$1,183,565	$1,183,560	$1,179,990
Change in present value of federal income taxes ($000)	--	$34	$30	($3,541)
Percentage change in federal income taxes	--	0.0%	0.0%	-0.3%
Present value of royalties collected ($000)	$785,543	$785,543	$785,543	$785,543
Change in present value of royalties ($000)	--	$0	$0	$0
Percentage change in royalties	--	0.0%	0.0%	0.0%

Source: EPA, 2000. Deepwater Production Loss Model.

Table 5-10

Impact of NSPS Options on All Deepwater GOM Platforms (1999$)

Type of Impact	Baseline Current	Option BAT 1	Option BAT 2	Zero Discharge
Projected lifetime discounted production (PVBOE)	608,917,710	608,917,710	608,917,710	608,917,710
Change in discounted production (PVBOE)	–	0	0	0
Percentage change in discounted baseline production	--	0.0%	0.0%	0.0%
Total projected lifetime production (BOE)	1,817,072,516	1,817,072,516	1,817,072,516	1,817,072,516
Change in total projected lifetime production (BOE)	–	0	0	0
Percentage change in discounted baseline production	--	0.0%	0.0%	0.0%
Present value of project net worth (NPV) ($000)	($2,042,101)	($2,040,789)	($2,040,919)	($2,100,948)
Change in NPV ($000)	--	$1,312	$1,182	($58,847)
Percentage change in NPV	--	0.1%	0.1%	-2.9%
Number of platforms ceasing production in first year (postcompliance)	0	0	0	0
Total number of production years	265	265	265	265
Average production years per platform (all platforms)	18	18	18	18
Average production years per platform (nonclosing platforms)	18	18	18	18
Total production years lost among closing platforms	--	0	0	0
Total production years lost among nonclosing platforms	--	0	0	0
Present value of federal income taxes collected ($000)	$1,380,806	$1,380,885	$1,380,875	$1,374,376
Change in present value of federal income taxes ($000)	--	$79	$69	($6,430)
Percentage change in federal income taxes	--	0.0%	0.0%	-0.5%
Present value of royalties collected ($000)	$1,026,532	$1,026,532	$1,026,532	$1,026,532
Change in present value of royalties ($000)	--	$0	$0	$0
Percentage change in royalties	--	0.0%	0.0%	0.0%

Source: EPA, 2000. Deepwater Production Loss Model.

Under the rejected BAT 1, the results are very similar to those for the selected option, a negligible increase in NPV and Federal taxes paid. Under the rejected zero discharge option, small and medium projects show a decline of 2.5 and 2.1 percent respectively in NPV over the life of the project while large projects show a 4.3 percent decline in NPV.

EPA has chosen the same option for NSPS as for BAT (discharge option 2). The selected option results in a cost **savings** to industry. As a result, EPA finds the rule economically achievable for new sources and concludes there will be no barriers to entry for new sources.

5.3 REFERENCES

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SECTION SIX

FINAL REGULATORY FLEXIBILITY ANALYSIS

6.1 INTRODUCTION

This section examines the projected effects of the costs from incremental pollution control on small entities as required by the Regulatory Flexibility Act (RFA, 5 U.S.C. 601 et seq., Public Law 96-354) as amended by the Small Business Regulatory Enforcement Fairness Act of 1996 (SBREFA). Although the Administrator has certified that this rule will not have a significant impact on a substantial number of small entities, EPA has prepared an analysis equivalent to a final regulatory flexibility analysis (FRFA). Section 6.2 reviews the steps suggested in Agency guidance to determine whether a regulatory flexibility analysis is required and how to identify significant impacts on small businesses. Section 6.3 responds to the regulatory flexibility analysis components required for a rule by Section 603 of the RFA. Section 6.4 is a detailed description of the small business economic analysis performed for the final rule.

6.2 REGULATORY FLEXIBILITY ANALYSIS COMPONENTS

Section 603 of the RFA requires that FRFA must contain the following:

- State the need for and objectives of the rule.
- Summarize the significant issues raised by public comments on the IRFA and the Agency's assessment of those issues, and describe any changes in the rule resulting from public comment.
- Describe the steps the Agency has undertaken to minimize the significant economic impact on small entities consistent with the stated objectives of the applicable statutes, including a statement of the factual, policy, and legal reasons for selecting the alternative adopted in the final rule and why each one of the other significant regulatory alternatives to the rule considered by the Agency which affect the impact on small entities was rejected.
- Describe/estimate the number of small entities to which the rule will apply or explain why no such estimate is available.

- # Describe the projected reporting, recordkeeping, and other compliance requirements of the rule, including an estimate of the classes of small entities that will be subject to the requirements of the rule.

The following sections address these issues.

6.2.1 Need for and Objectives of the Rule

The rule is being promulgated under the authority of Sections 301, 304, 306, 307, 308, and 501 of the Clean Water Act, 33 U.S.C. Sections 1311, 1314, 1316, 1317, 1318, and 1361. Under these sections, EPA sets standards for the control of discharge of pollutants for the Offshore and Coastal Oil and Gas Point Source Subcategories.

The objective of the CWA is to "restore and maintain the chemical, physical, and biological integrity of the Nation's waters." To assist in achieving this objective, EPA issues effluent limitations guidelines, pretreatment standards, and new source performance standards for industrial dischargers. Sections 301, 304, and 306 authorize EPA to issue BPT, BAT, and NSPS regulations.

6.2.2 Significant Issues Raised by Public Comments on the IRFA

No comments on the IRFA were received, either at proposal or in comments on EPA's Notice of Data Availability.

6.2.3 Steps Taken By the Agency To Minimize Significant Economic Impact on Small Entities

The small entities currently drilling in the deepwater regions of the Gulf of Mexico primarily undertake exploratory drilling. The selection of the BAT 2 option minimizes economic impacts on small entities because it provides cost savings for drilling most wells.

6.2.4 Estimated Number of Small Entities To Which the Rule Will Apply

6.2.4.1 Small Business Definitions

The RFA and SBREFA both define "small business" as having the same meaning as the term "small business concern" under Section 3 of the Small Business Act (unless an alternative definition has been approved). When making classification determinations, SBA counts receipts or employees of the entity and all of its domestic and foreign affiliates (13 CFR.121.103(a)(4))). SBA considers affiliations to include:

- stock ownership or control of 50 percent or more of the voting stock or a block of stock that affords control because it is large compared to other outstanding blocks of stock (13 CFR 121.103(c)).
- common management (13 CFR 121.103(e)).
- joint ventures (13 CFR 121.103(f)).

EPA interprets this information as follows:

- Sites with foreign ownership are not small (regardless of the number of employees or receipts at the domestic site).
- The definition of small is set at the highest level in the corporate hierarchy and includes all employees or receipts from all members of that hierarchy.
- If any one of a joint venture's affiliates is large, the venture cannot be classified as small.

Effective October 2000, SBA switched the basis for the size standards from Standard Industrial Classification (SIC) to North American Industrial Classification System (NAICS). Table 6-1 maps the SIC and NAICS classifications for this industry.

Table 6-1

SIC and NAICS Size Standards

Industry	SIC	NAICS	NAICS Standard (Number of Employees or Revenue in $Millions)
Crude Petroleum and Natural Gas Extraction	1311	211111	500
Drilling Oil and Gas Wells	1381	213111	500
Support Activities for Oil and Gas Operations	1389	213112	$5
Other Oil Field Exploration Services	1382	213112	$5
Geophysical Mapping and Surveying Services	1382	54136	$4
Deep Sea Foreign Transportation of Freight	4412	483111	500

6.2.4.2 Estimated Number of Small Business Entities

The small business definitions and the methodology were outlined in the April 2000 NODA and the February 1999 Proposal Economic Analysis and have not changed. Briefly, EPA relied on Small Business Administration's size standards to determine whether a firm is a small business. If EPA could not find employment or revenue data to confirm a firm's size, it was classified as "potentially" small. EPA identified a total of 40 small and potentially small firms as of the end of 1999.

Table 6-2 presents the available financial data on all publicly traded small firms in the analysis, providing some additional comparative measures of financial health: a posttax return on assets ratio, a posttax return on equity ratio, and a posttax return on revenues (or profit margin).[1] The typical small firm generally has smaller revenues, total assets, and owner equity than the typical large firm, but small size does not necessarily mean less healthy financially (see Table 3-3 in Section Three).

[1]Posttax returns are used because the OGJ 200, from which EPA obtained most of the summary financial data, presents net income. Because some small firms might not pay corporate taxes, some of these ratios might overstate returns by roughly a third for certain small firms.

Table 6-2

Financial Data On Small Operators in the Gulf of Mexico ($1,000s)

Operator	Number of Employees	Assets	Equity	Revenues	Net Income	Return on Assets	Return on Equity	Profit Margin
3Tec Energy Corporation	46	149,244	38,113	22,020	(3,432)	-2.3%	-9.0%	-15.6%
ATP Oil & Gas Corporation	25	107,054	(3,655)	42,684	18,228	17.0%	NA	42.7%
Aviva Petroleum Inc.	61	8,986	(11,483)	7,053	(403)	-4.5%	NA	-5.7%
Barrett Resources Corp.	202	884,301	363,648	1,004,781	20,828	2.4%	5.7%	2.1%
Basin Exploration Inc	75	248,905	175,163	71,630	12,036	4.8%	6.9%	16.8%
Bellwether Exploration	24	171,761	23,314	70,747	8,813	5.1%	37.8%	12.5%
Callon Petroleum Ltd.	94	259,877	124,380	38,993	2,627	1.0%	2.1%	6.7%
Forcenergy, Inc.	258	675,401	240,000	269,023	109,852	16.3%	45.8%	40.8%
Forest Oil Corp.	272	800,052	318,984	357,258	19,043	2.4%	6.0%	5.3%
Magnum Hunter Resources	89	306,110	53,640	69,626	(6,828)	-2.2%	-12.7%	-9.8%
Mariner Energy Inc	74	297,512	65,026	52,468	(9,970)	-3.4%	-15.3%	-19.0%
Meridian Resource Corp.	94	477,719	163,860	133,361	16,867	3.5%	10.3%	12.6%
Newfield Exploration Co.	227	781,561	375,018	283,583	33,204	4.2%	8.9%	11.7%
Panaco Inc	34	135,438	(26,875)	42,972	(35,027)	-25.9%	NA	-81.6%
Petroquest Energy Inc.	24	29,901	18,105	8,607	(310)	-1.0%	-1.7%	-3.6%
Petsec Energy, Inc.	23	93,508	(71,313)	31,260	(29,488)	-31.5%	NA	-94.3%
Pogo Producing Co.	165	949,401	268,512	275,116	22,134	2.3%	8.2%	8.0%
Range Resources Corp.	136	752,368	127,171	201,364	(7,793)	-1.0%	-6.1%	-3.9%
Spinnaker Exploration Company	35	189,553	177,102	34,786	(1,337)	-0.7%	-0.8%	-3.8%
St.Mary Land and Exploration Co.	142	230,438	188,772	75,029	82	0.0%	0.0%	0.1%
Stone Energy Corp.	103	441,238	265,587	149,134	(26,490)	-6.0%	-10.0%	-17.8%
Titan Exploration, Inc.	76	268,798	160,851	75,717	(8,274)	-3.1%	-5.1%	-10.9%
Westport Resources	94	271,477	140,011	73,763	(3,126)	-1.2%	-2.2%	-4.2%
Totals	2,373	$8,530,603	$3,173,931	$3,390,975	$131,236	-23.6%	68.6%	-110.8%
Medians	89	$268,798	$140,011	$71,630	($310)	-0.7%	0.0%	-3.6%
Minimum	23	$8,986	($71,313)	$7,053	($35,027)	-31.5%	-15.3%	-94.3%
Maximum	272	$949,401	$375,018	$1,004,781	$109,852	17.0%	45.8%	42.7%

Source: Oil & Gas Journal. OGJ 200, 2000; Pennwell Petroleum Directory, 1998; SEC's Edgar Database at http://www.sec.gov.; Hoovers Online at http://www.hoovers.com; and Lycos Companies Online at http://www.companiesonline.com

Among all small firms identified (including those identified at proposal, the median assets (1999 data) for this group (among publicly held firms) is about $270 million, median equity is about $140 million, and median revenues are about 72 million. Due to a relatively hard year for the oil and gas industry, the median net income is a loss of about $310,000. Median return on assets is -0.7 percent and median return on equity is zero percent, with median net income to revenues (net profit margin) is about -3.6 percent. Median employment is approximately 89 persons. In the oil and gas industry, financial health varies as swiftly as oil prices. In 1999, the average domestic first purchase price was $15.56/bbl and the wellhead price for gas was $2.08/Mcf. In the first seven months of 2000, oil prices averaged $25.50/bbl and gas prices averaged $2.82/Mcf (DOE, 2000). The financial health of the oil firms should show a corresponding increase.

6.3 SMALL BUSINESS ANALYSIS

EPA certifies that no small businesses incur significant economic impacts as a result of the selected option. Only shallow water wells drilled with SBF in the baseline show a cost increase under the selected option. EPA did not identify any small firms currently using SBFs in shallow water.

EPA used a sales test to determine the magnitude of impacts that might be incurred by small firms that use SBFs under the rejected zero discharge option. As mentioned above, EPA did not identify any small firms using SBFs in shallow water. Therefore, EPA has determined that the likeliest users of SBF in shallow water locations would be large operators who use SBF in deep water operations. Thus small firms with deep water operations would be the potentially affected firms. At proposal, EPA had identified only one small business that was drilling in the deep water regions of the Gulf of Mexico. Using MMS drilling data through 1999, however, EPA has identified one additional small firm drilling in the Gulf of Mexico in water depths exceeding 1,000 feet. This small firm and the one identified at proposal are primarily drilling exploratory wells and have averaged 2 to 4 wells, respectively, drilled in deepwater in 1998 and 1999. If the zero discharge option had been selected, costs would have been estimated to be 5 percent to 8 percent of revenues among these firms.

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SECTION SEVEN

COST-BENEFIT ANALYSIS

EPA chose to quantitatively and qualitatively compare the costs and benefits of the preferred discharge option. The findings are presented in detail in EPA's Environmental Assessment Report.[1] The selected option, BAT 2, results in a **savings** to industry of $ 49 million, including both existing and new operations. Not only does industry save money, but EPA also projects positive benefits:

- Fewer SBF wells are needed to produce the same output from the same formations than WBF wells because SBF fluids are more efficient and allow more directional drilling.
- Less fluid is needed for SBF wells than for WBF wells because an SBF borehole is slightly over half the diameter of a WBF borehole. Therefore, less fluid is discharged with lower impacts on the benthic community.
- Energy requirements are lower because SBF wells are drilled faster and fewer trips are needed to transport cuttings to shore for disposal. Overall, EPA estimates a savings of nearly 200,817 BOE/yr (195,124 for BAT and 5,693 for NSPS).
- Air emissions are lower because the drilling equipment including solids removal runs for fewer days per well and fewer trips are needed to transport cuttings to shore for disposal. EPA estimates a reduction of nearly 3,073 tons/yr for BAT sources and an increase of 145 tons/yr for NSPS sources for a net reduction of about 2,927 tons/yr.

The rejected BAT 1 option shows slightly larger reductions in energy and air emissions than the selected option. The selected option does not permit the discharge of fine particles separated from the drilling fluid, hence it involves more annular injection or transport to shore than BAT 1.

Under the rejected zero discharge option, approximately 187 million pounds would not be discharged from existing sources and 10 million pounds would not be discharged from new sources.

[1] U.S. EPA, 2000. *Environmental Assessment of Final Effluent Limitations Guidelines and Standards for Synthetic Based Drilling Fluids and Other Non-Aqueous Drilling Fluids in the Oil and Gas Extraction Point Source Category*. EPA-821-B-00-014.

However, the reduction in pollutant loadings is offset by:

- $29 million cost annually to industry.

- An increase of 51 million pounds of WBF and WBF-cuttings being discharged to the U.S. offshore waters because operations would switch from SBF to less efficient WBF drilling.

- Increased energy use equal to nearly 376,731 BOE/yr (358,664 for BAT and 18,067 for NSPS).

- Higher air emissions because the drilling equipment including solids removal runs for more days per well and more trips are needed to transport cuttings to shore for disposal. EPA estimates an increase of nearly 5,602 tons/yr for BAT sources and 528 tons/yr for NSPS sources for a net increase of about 6,130 tons/yr.

- An increase of 24 million lbs of OBF-cuttings being injected onsite and 157 million lbs of OBF cuttings being hauled ashore for disposal.

SECTION EIGHT

ENVIRONMENTAL JUSTICE ANALYSIS

Section 8 examines whether the rejected zero discharge option, BAT 3, may have a potential environmental justice effect on minority and low-income populations surrounding onshore injection wells and landfarming facilities. Appendix C explains the methodology and provides supporting documentation for this analysis. Since the early 1970s, there has been concern that minority and low-income populations experience higher-than-average exposure to environmental contaminants (Bryant, 1992; Bullard, 1992). These populations may bear disproportionate environmental and human health impacts because disposal facilities tend to be in areas with minority and economically disadvantaged populations.

Environmental justice ensures that no population will be subjected to disproportionate environmental threats to public health. The U.S. EPA defines environmental justice as:

> "The fair treatment and meaningful involvement of all people regardless of race, color, national origin, or income with respect to the development, implementation, and enforcement of environmental laws, regulations, and policies. Fair treatment means that no group of people, including racial, ethnic, or socioeconomic group should bear a disproportionate share of the negative environmental consequences resulting from industrial, municipal, and commercial operations or the execution of federal, state, local, and tribal programs and policies." (http://es.epa.gov/oeca/main/ej/index.html)

Under federal mandate, no stages of policy, guidance, activity, and regulation development should cause minority and low-income populations to experience significantly higher-than-average exposure rates to toxic and hazardous contaminants. On February 11, 1994, the White House issued Executive Order 12898 on Federal Actions to address environmental justice in minority and low-income populations. The order, *Federal Actions to Address Environmental Justice in Minority Populations and Low-Income Populations*, is designed to focus federal agencies' attention on environmental and human health conditions in minority and low-income communities. The order directs each federal agency "to make achieving environmental justice part of its mission by identifying and addressing, as appropriate, disproportionately high and adverse human health or environmental effects of its programs, policies, and activities on minority populations and low-income populations" (Clinton, 1994).

8.1 OVERVIEW OF THE ENVIRONMENTAL JUSTICE SCREENING ANALYSIS

The objective of this environmental justice screening analysis is to determine whether the zero discharge option of the effluent guidelines may disproportionately affect minority and/or low-income populations. The analysis identifies disposal facilities that accept SBFs and are surrounded by significantly higher-than-average minority and/or low-income populations.

The Gulf of Mexico is associated with the only known current use of SBFs and discharge of SBF cuttings (U.S. EPA, 1999). Disposal facilities that accept SBFs are within U.S. EPA Region 6, in Texas and Louisiana (Veil, 1999). To meet the general directive of Executive Order 12898, Region 6 developed an environmental justice methodology tailored to the states within its region (Johnston, 2000). This methodology provides for a tier one screening analysis to evaluate whether sociodemographic data indicate that a disposal facility should be identified as a potential environmental justice case. If the percentage of minority and low-income people living within specified distances of a disposal facility are significantly higher than the state average, the site would be considered a potential environmental justice case. A tier one screening was performed for all disposal facilities accepting SBFs, and the methodology and results are detailed in Appendix C.

A tier one screening is limited because it does not include a site-specific analysis of the populations risk of exposure to contaminants. In a tier two analysis, potential environmental justice cases would undergo further analysis to consider the fate and transport mechanism of the involved facilities' contaminants and to determine if the populations would be subject to high and adverse environmental and public health effects resulting from contaminants. Additionally, locations of other facilities near the populations would be assessed to determine possible cumulative exposure to contaminants. The objective of this environmental justice screening analysis is to identify potential environmental justice cases. Because the selected option is not the option which might have possible environmental justice concerns—zero discharge—a tier two analysis has not been conducted.

8.2 IDENTIFICATION OF OIL AND GAS WASTE DISPOSAL SITES

Under the zero discharge option, SBFs arriving onshore would be disposed of by Newpark Environmental Services and U.S. Liquids. Appendix C shows the locations of the marine transfer facilities, process facilities, injection sites, and landfarming facilities owned by these companies. With the exception of the landfarming facilities, all the facilities are owned by Newpark Environmental Services. The environmental justice screening analysis assumes that 80 percent of SBFs would be disposed of by Newpark and 20 percent would be disposed of by U.S. Liquids (Newman, 2000).

8.3 SUMMARY OF METHODOLOGY

A detailed discussion of the environmental justice methodology is presented in Appendix C. Briefly, to identify potential EJ sites, EPA used a screening tool developed by Region 6 (the location of the sites in question). The methodology assesses the characteristics of neighborhoods located within a 1- and 50-square mile buffer zone around toxic or hazardous waste or facilities that emit toxic or hazardous waste. A site is determined to be a potential environmental justice case if the buffer area has a significantly higher minority and/or low-income populations than the state average. Buffer areas are used because residences closer to the source are likely to have a higher risk of exposure.

The GIS application uses an index formula developed by Region 6 to mathematically compare the percentage of the population groups within a buffer area to the state average percentages (U.S. EPA, 1996). The index evaluates the potential *degree of vulnerability* for the population exposed to the facility. The index for this tier one screening analysis does not consider the *degree of impact* from potential exposure and toxicity. A tier two risk screening analysis could determine the degree of impact for sites identified as potential environmental justice cases.

8.4 RESULTS

EPA conducted thirteen Region 6 environmental justice screening analyses to determine whether the facilities are potential environmental justice cases. A GIS application used minority, population, and low-income data to rank each facility and produce mapping and tabular outputs. Detailed results and maps are provided in Appendix C.

Of the 13 disposal sites identified, five are estimated to be potential environmental justice sites. Morgan City, Venice, Bateman Island, and Mermentau facilities are potential environmental justice cases within the 1-square mile area. Port Fourchon and Venice facilities are potential environmental justice cases within the 50-square mile area.

8.5 REFERENCES

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